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(54) Abstract Title

An expandable liner for a junction in a wellbore and a method for use of said liner

(57) An expandable sleeve junction (10), has a sleeve (12), having slots (14) to facilitate expansion of the sleeve and a hook (16) to support the junction liner within a secondary borehole (32 Fig 3) and orient a primary borehole access window (18) with a primary borehole (30 Fig 3), from which the secondary borehole (32 Fig 3) extends. As expansion of the sleeve (12) will create large openings to exist throughout the sleeve (12), expandable material (20) is provided around the outside of the sleeve (12) to seal off and screen out any matter from entering the primary borehole (30 Fig 3). A shield (22 Fig 2) is constructed to nest within the window (18) of the sleeve (12) and has a boundary area (24 Fig 2) which overlaps with the edges of the window (18) to prevent extrusion of a packer (42) there through upon expansion of the packer (42 Fig 5). In use the sleeve is traversed down the primary hole (30 Fig 3) to the junction with the secondary hole (32 Fig 3). A bent sub (38 Fig 4) is provided to allow the sleeve (12) to enter the secondary hole (32 Fig 3). The hook (16) ensures the window (18) is oriented with the primary borehole (30 Fig 3). The packer (42 Fig 5) is expanded which urges the junction (10) against borehole (32 Fig 3). Upon completion the junction (10) is permanently deformed to exhibit a larger outside diameter than it possessed at run-in, giving structural support to borehole (32 Fig 3). The packer (42 Fig 5) is then deflated and removed.

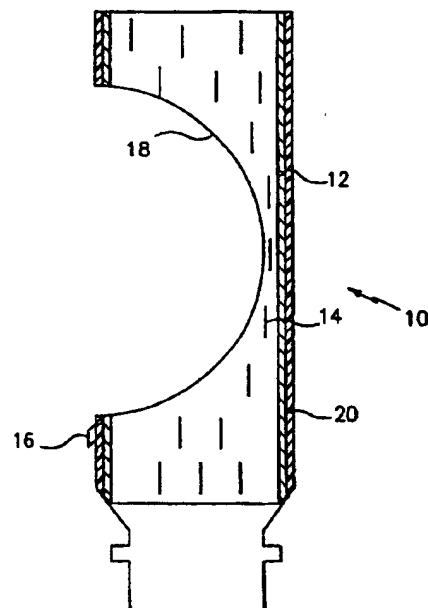


FIG. 1

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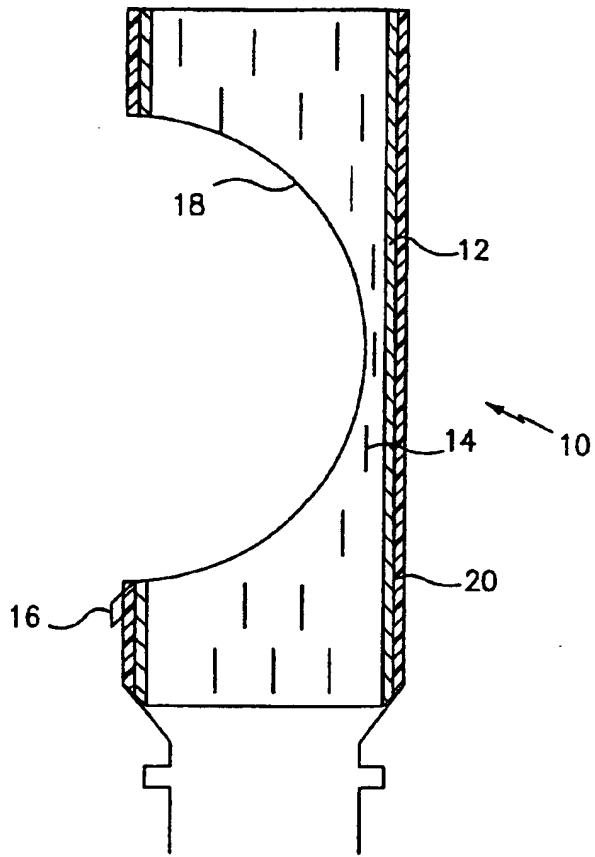


FIG. 1

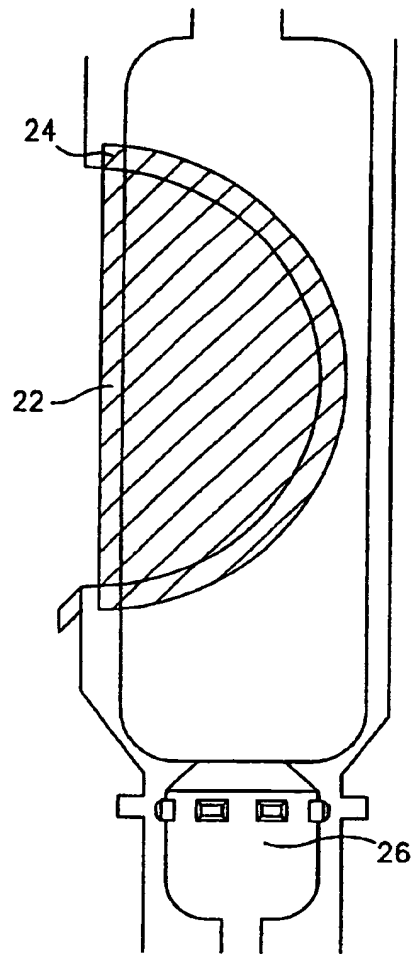
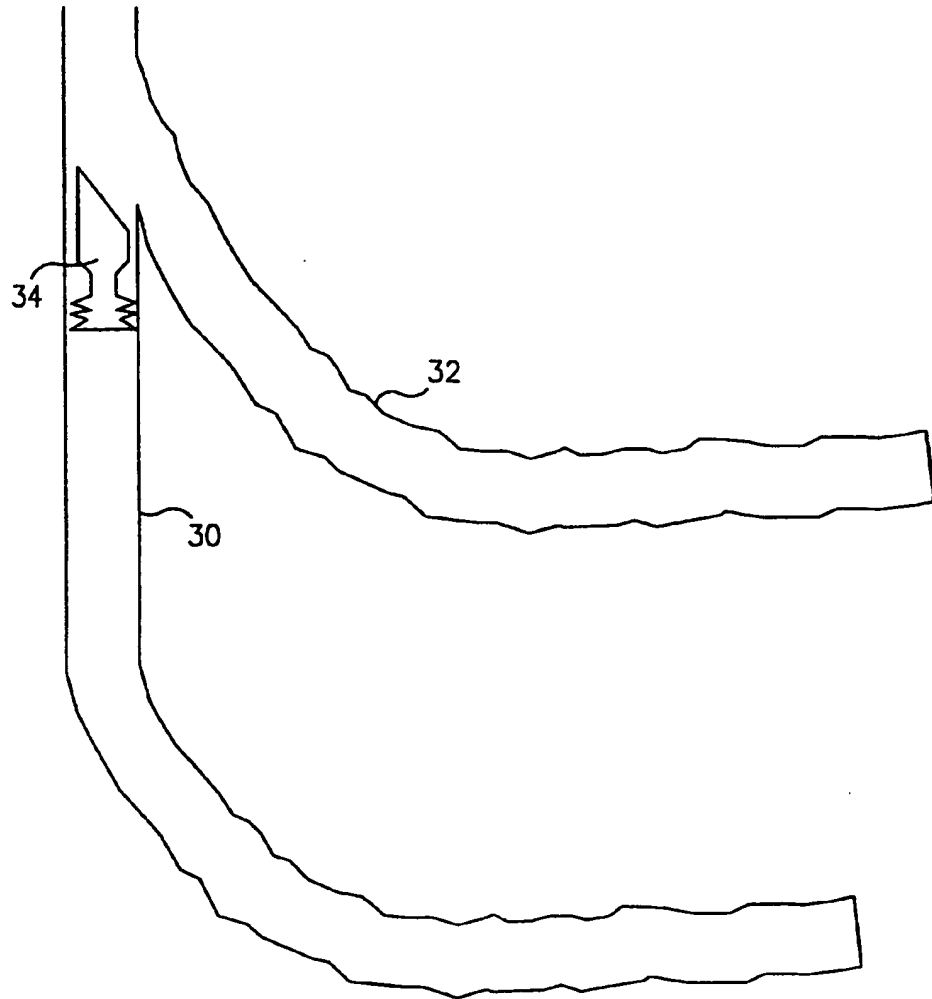
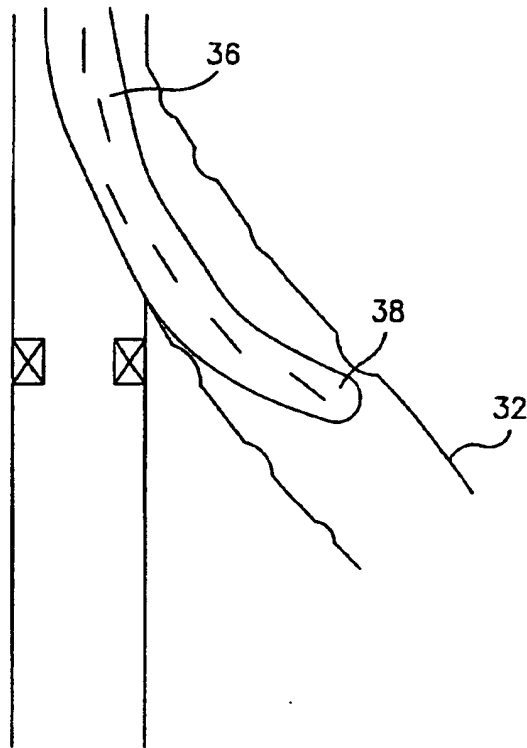


FIG. 2

*FIG. 3*

*FIG. 4*

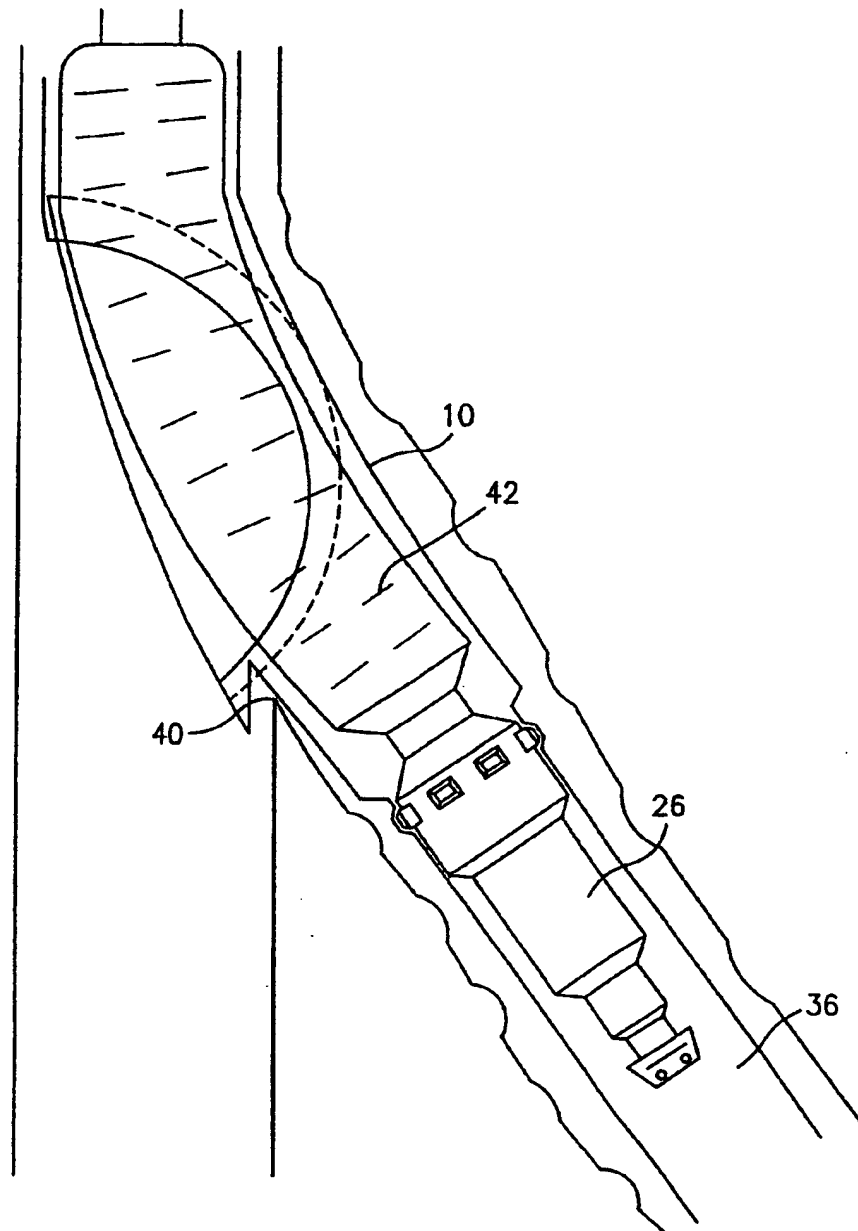
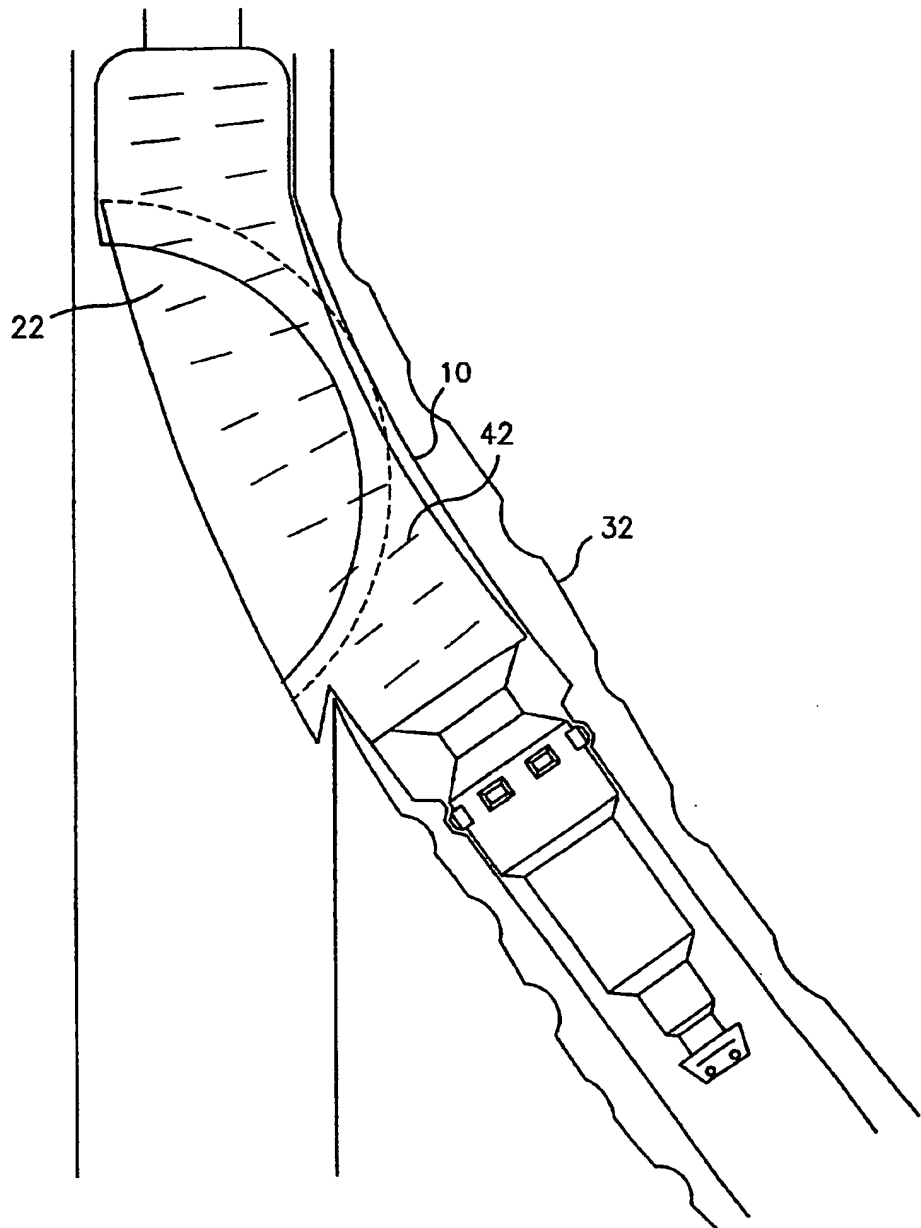
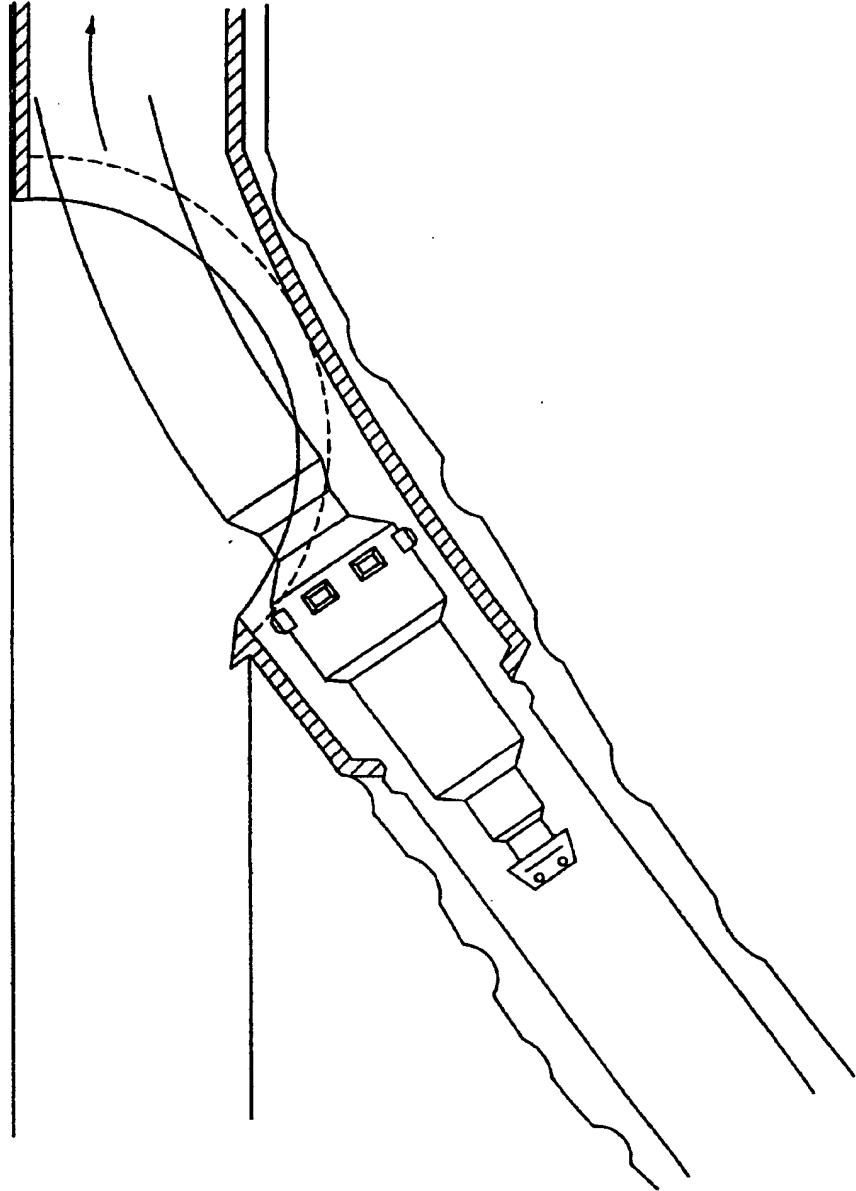
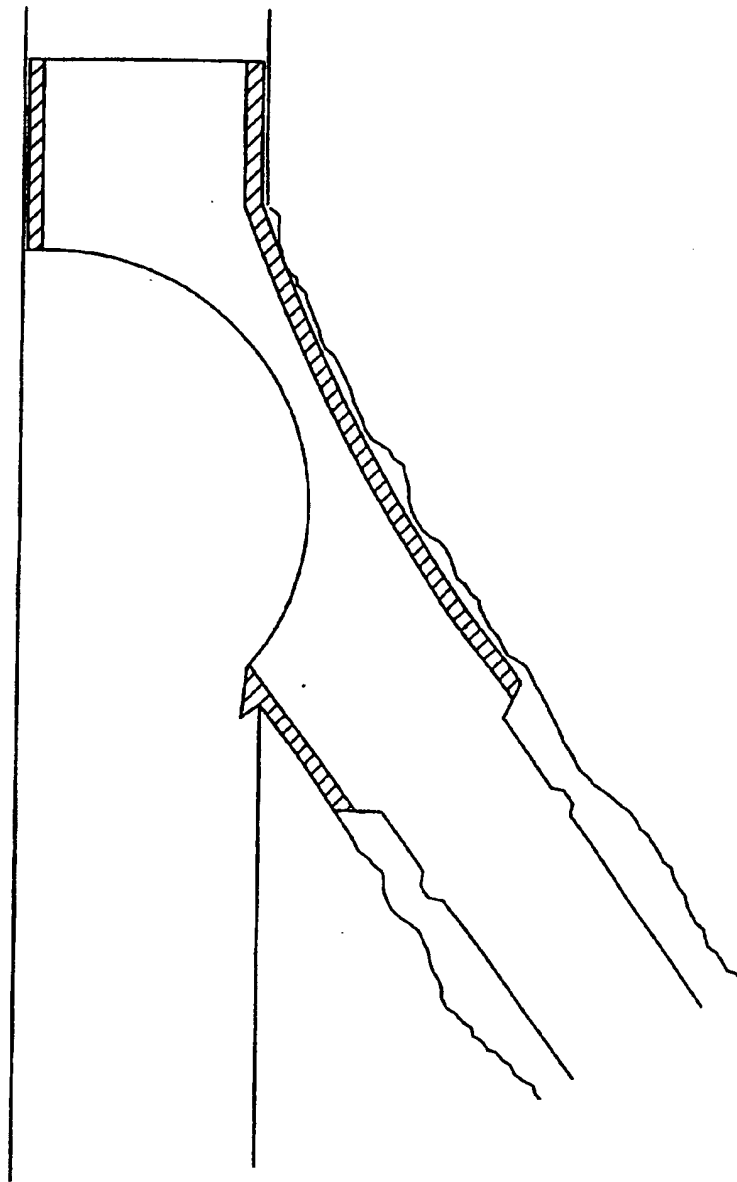


FIG. 5

*FIG. 6*

*FIG. 7*

*FIG. 8*

METHOD AND APPARATUS FOR COMPLETING A WELLBORE

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BACKGROUND OF THE INVENTION

Field of the Invention

The invention relates to the field of hydrocarbon production. More particularly, the invention relates to improving the junction between a main wellbore and lateral wellbore to prevent sand or other solids from entering the main wellbore through the junction window.

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Prior Art

Liners have been run in lateral boreholes with great success commercially. Generally a lateral borehole is drilled off a whipstock through a milled window in a cased or uncased primary borehole. It should be understood that the terms "primary" and "lateral" as used in this application are intended to mean a primary borehole being the borehole from the surface and a lateral extending from that primary wellbore but also encompass a secondary lateral borehole drilled off a preexisting lateral wellbore. In that case the preexisting lateral borehole is considered to be the "primary" borehole and the secondary lateral borehole is considered to be the "lateral" borehole for purposes of this disclosure.

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Subsequent to milling the window in the primary borehole and drilling the lateral borehole, a running tool is introduced to the primary borehole carrying a lateral liner. At the uppermost portion of lateral liner a slotted sleeve has been used to provide some structural support to the junction of the lateral borehole and the primary borehole. This is particularly useful in unconsolidated well formations and allows rapid completion of lateral borehole junctions in order to reduce the costs associated

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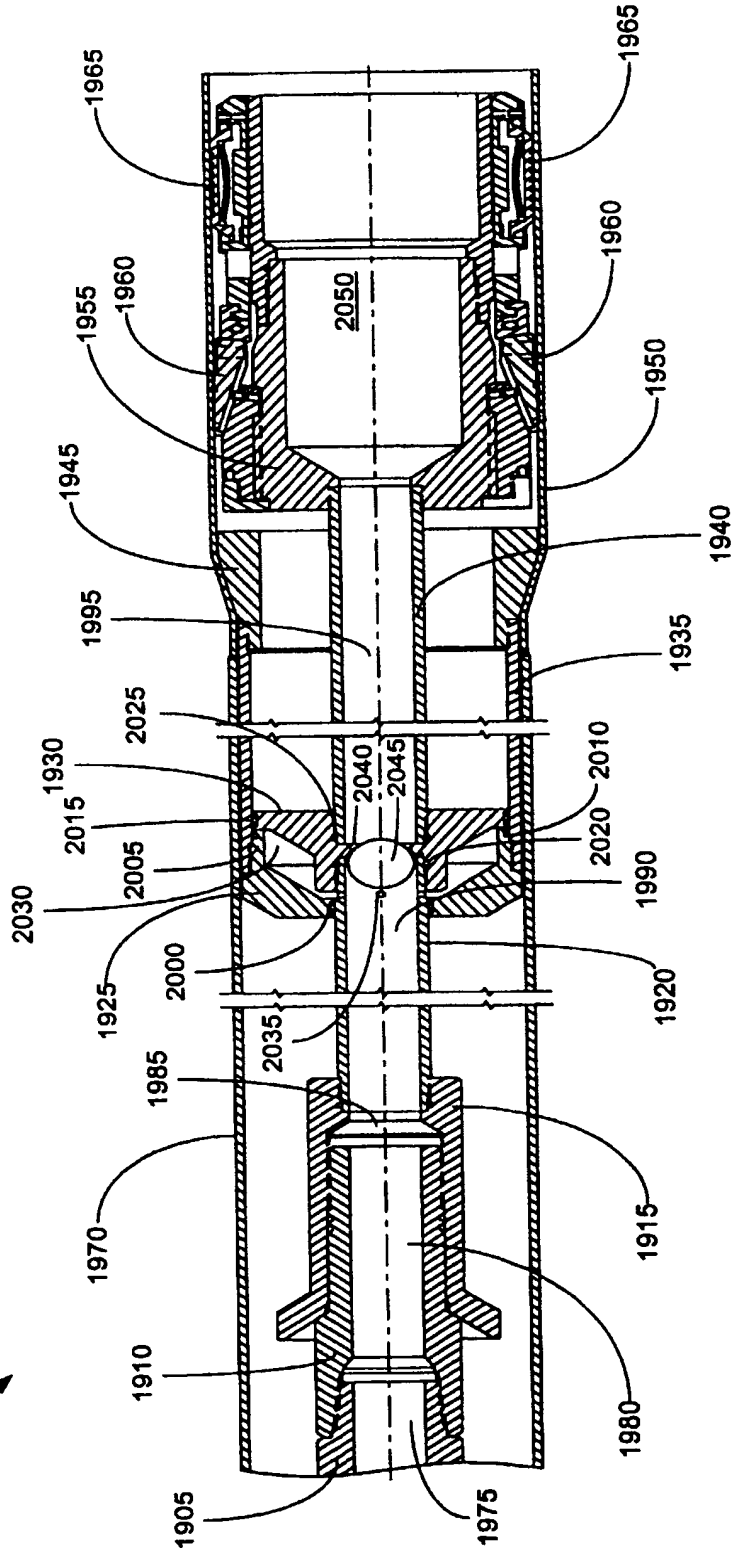
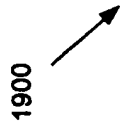


FIGURE 15

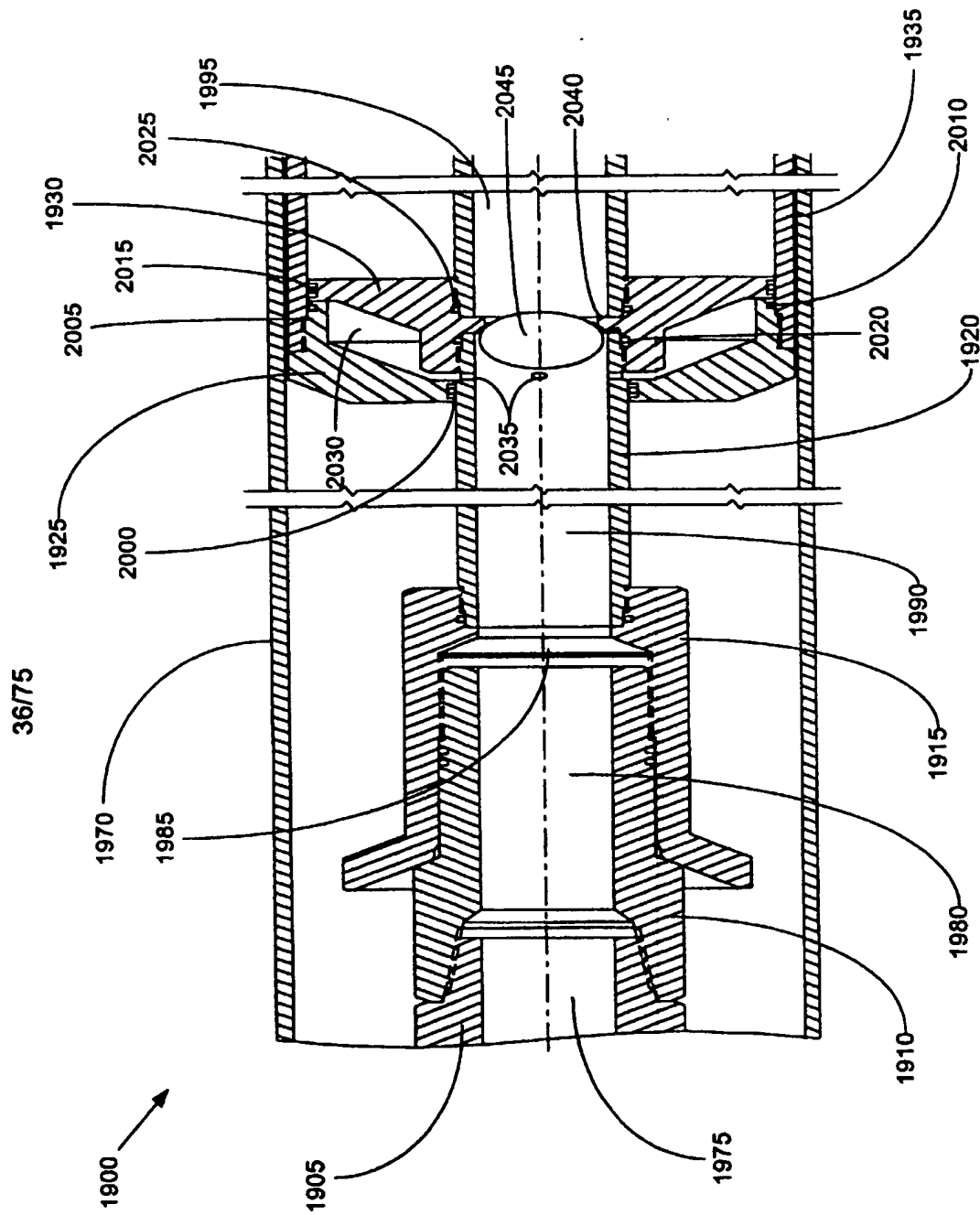


FIGURE 15a

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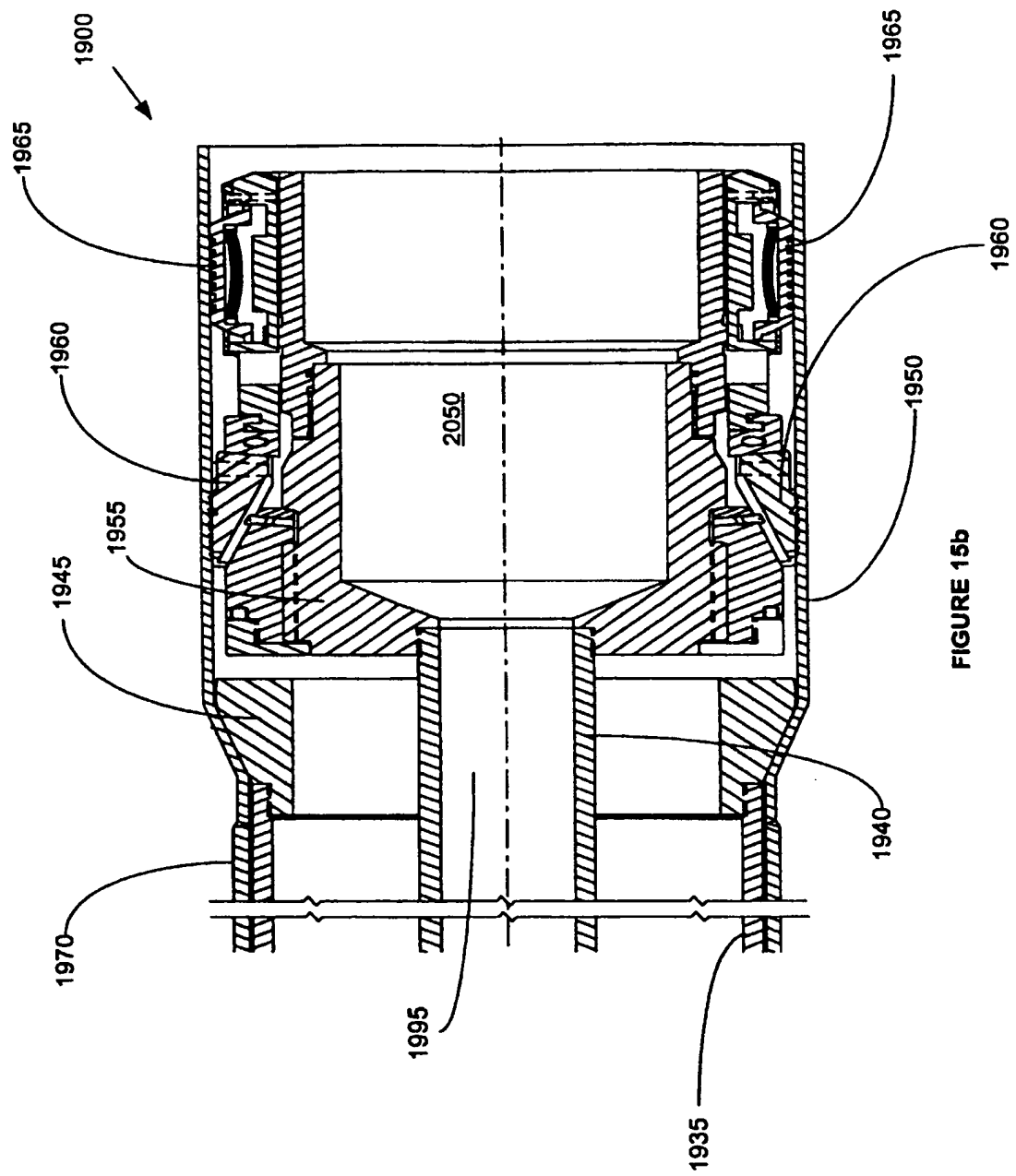


FIGURE 15b

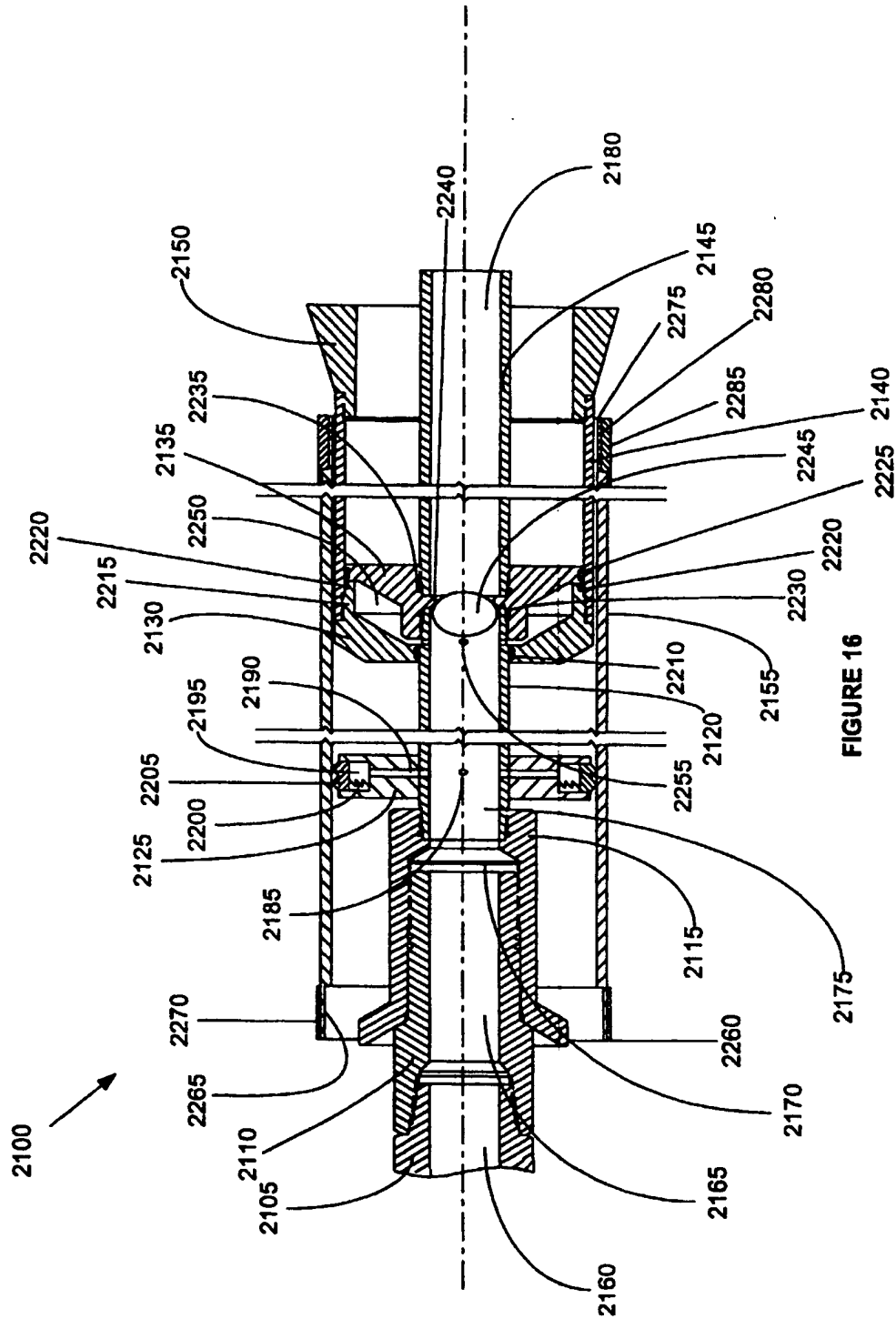


FIGURE 16

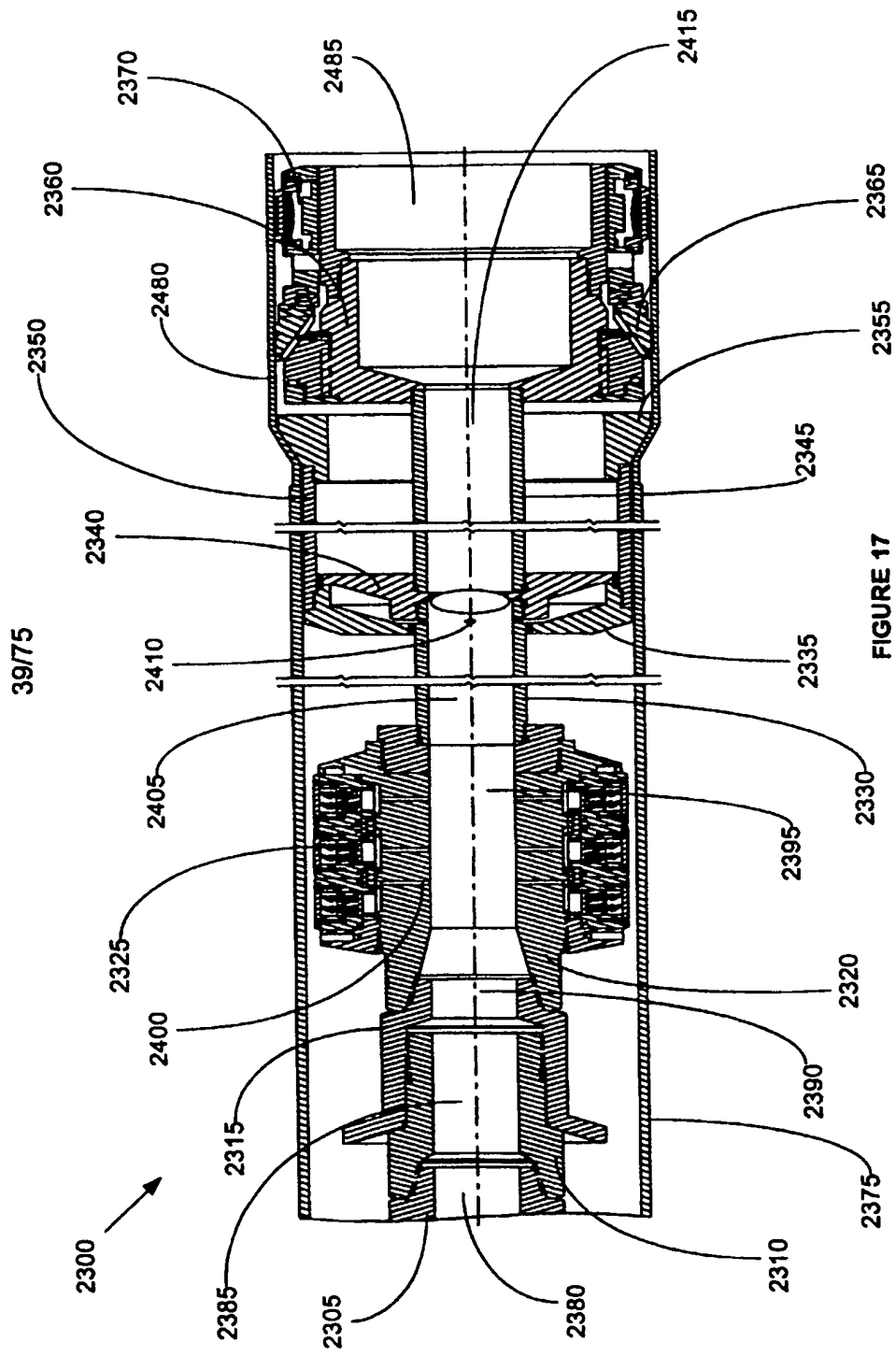


FIGURE 17

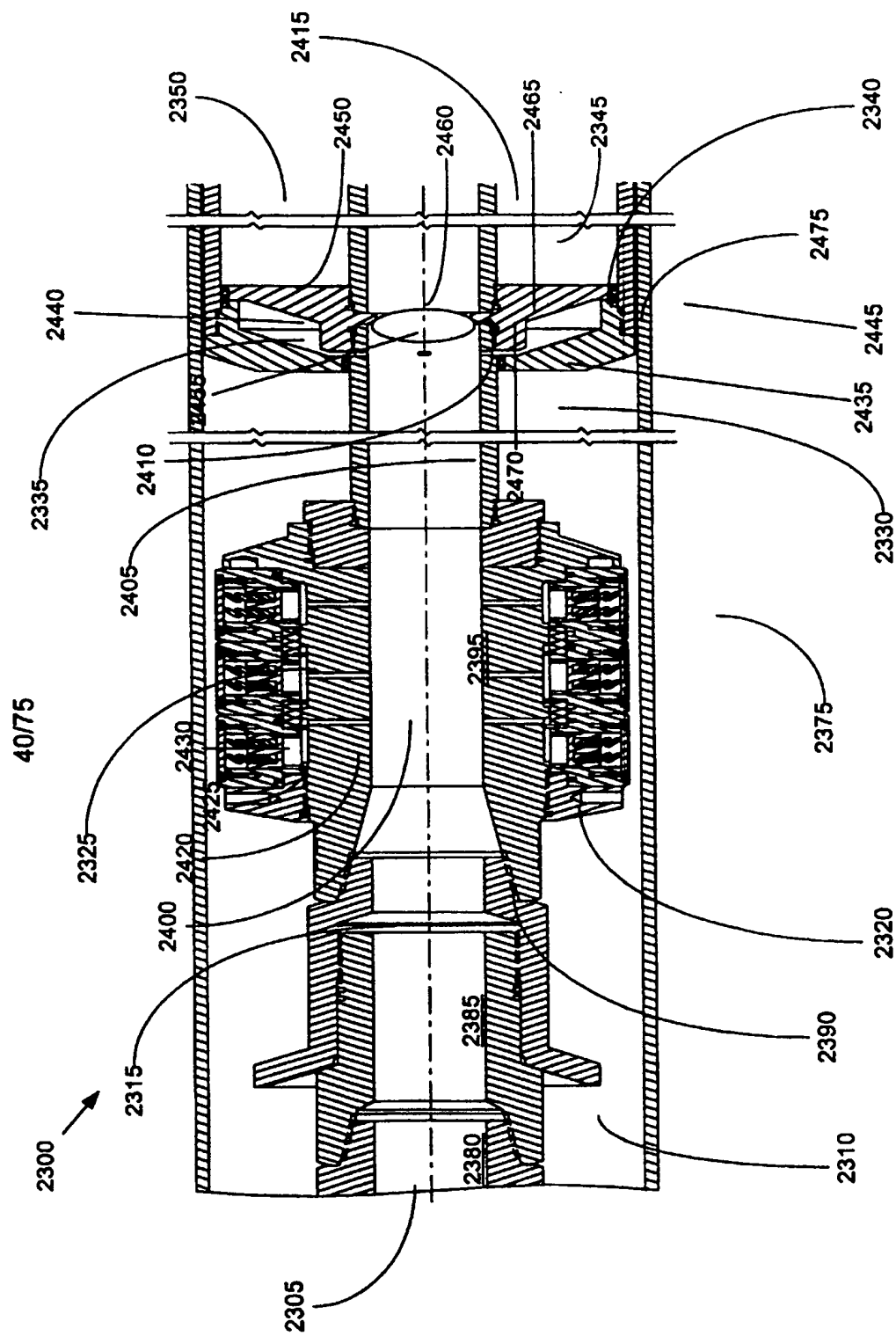


FIGURE 17a

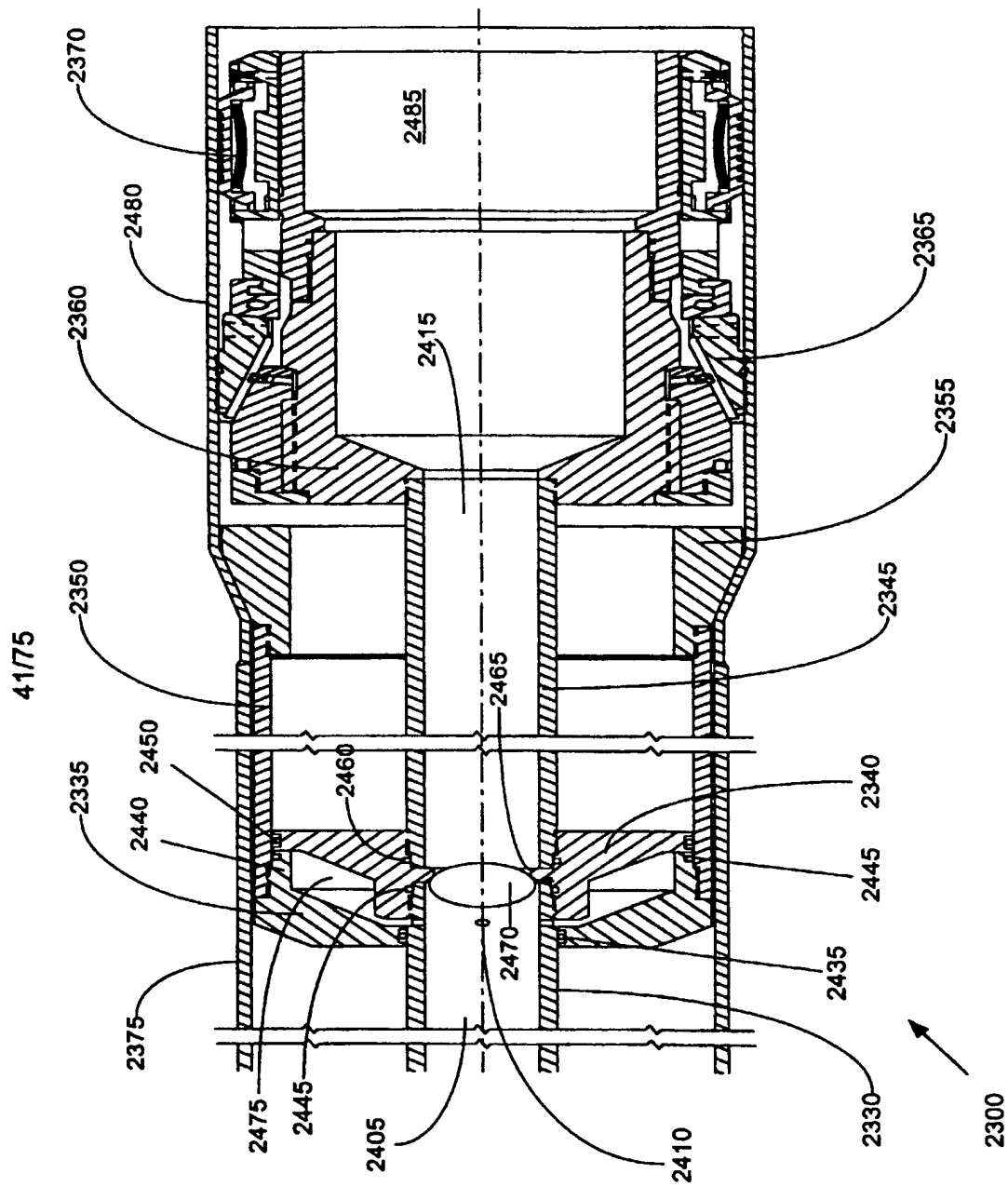


FIGURE 17b

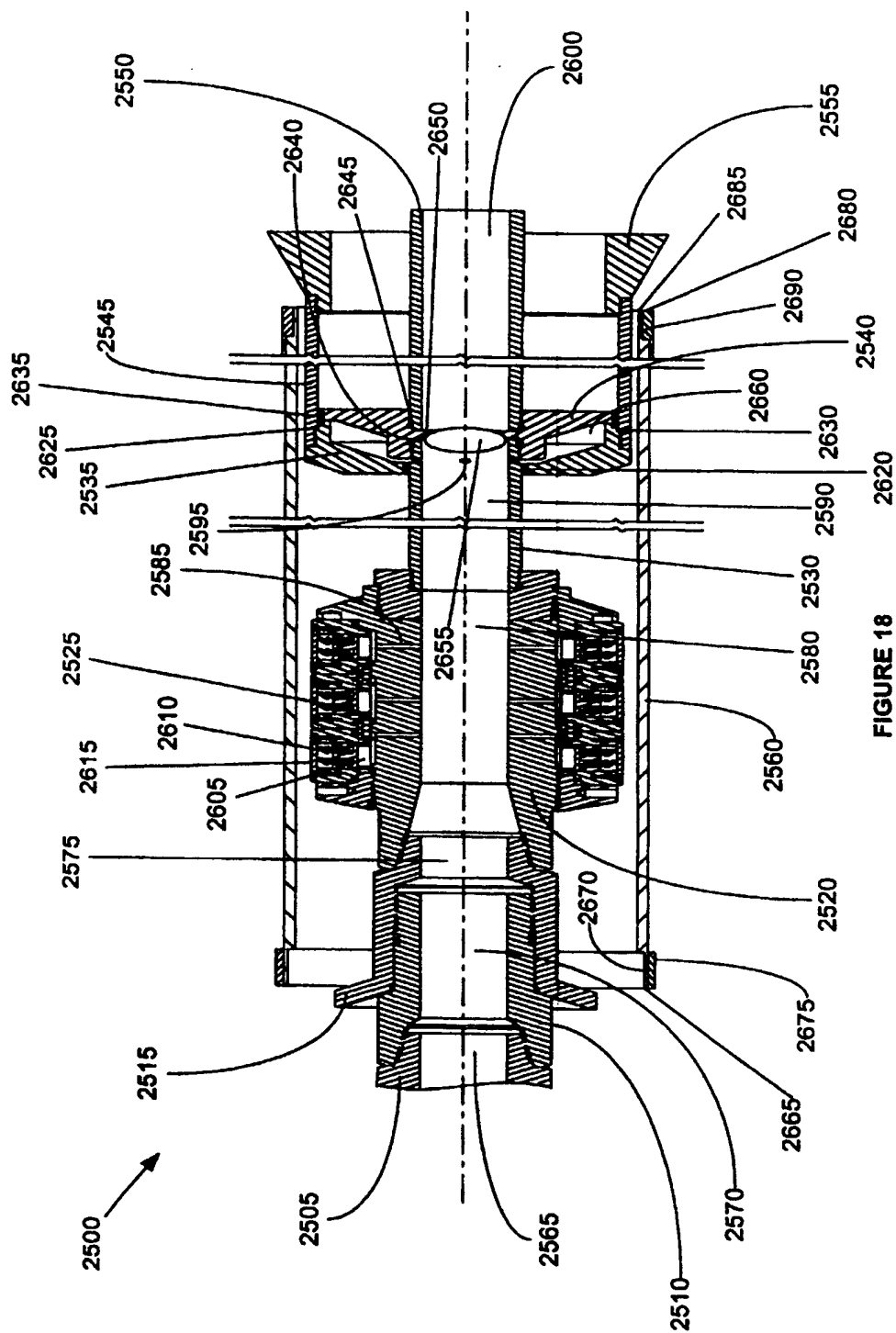


FIGURE 18

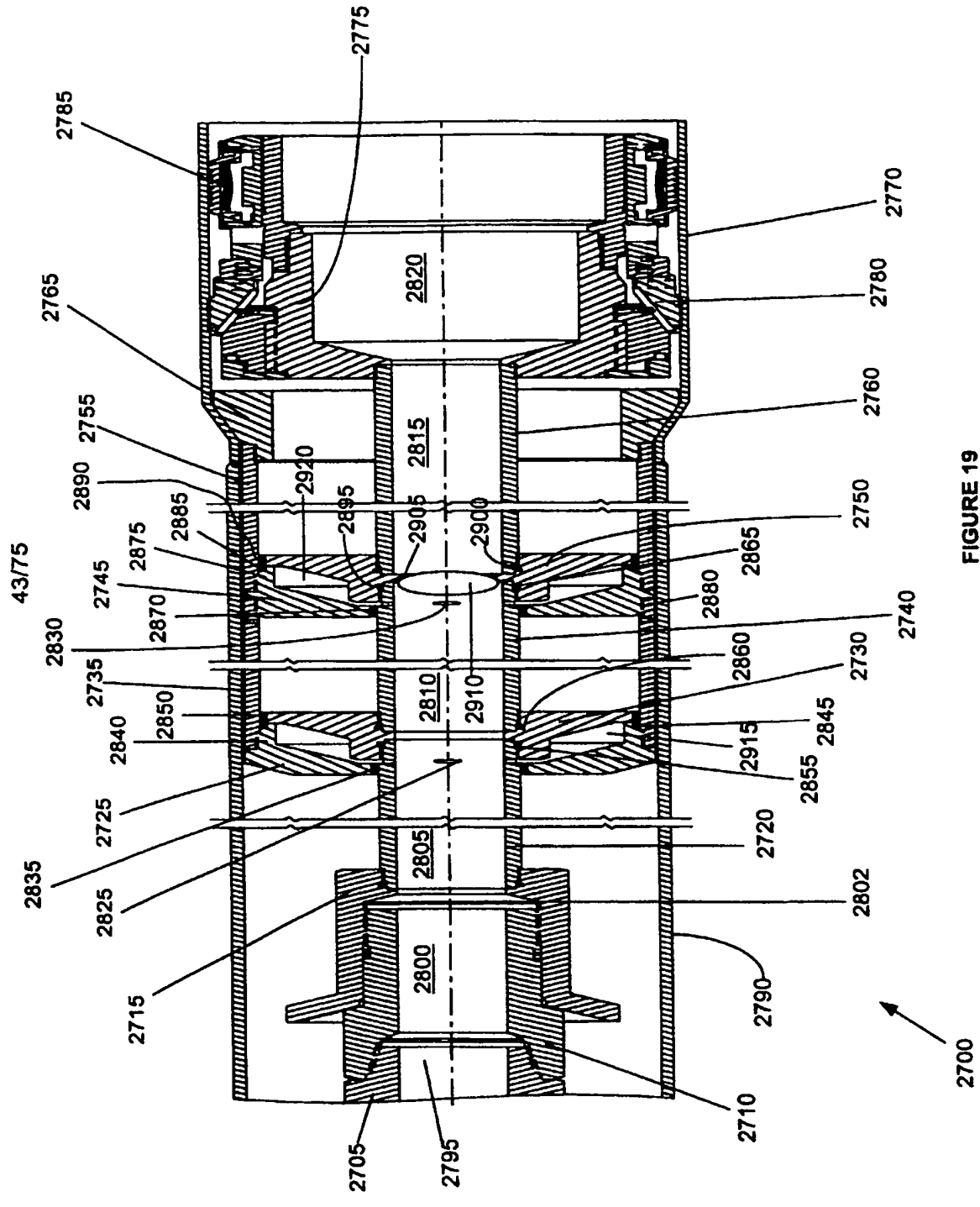


FIGURE 19



FIGURE 19a

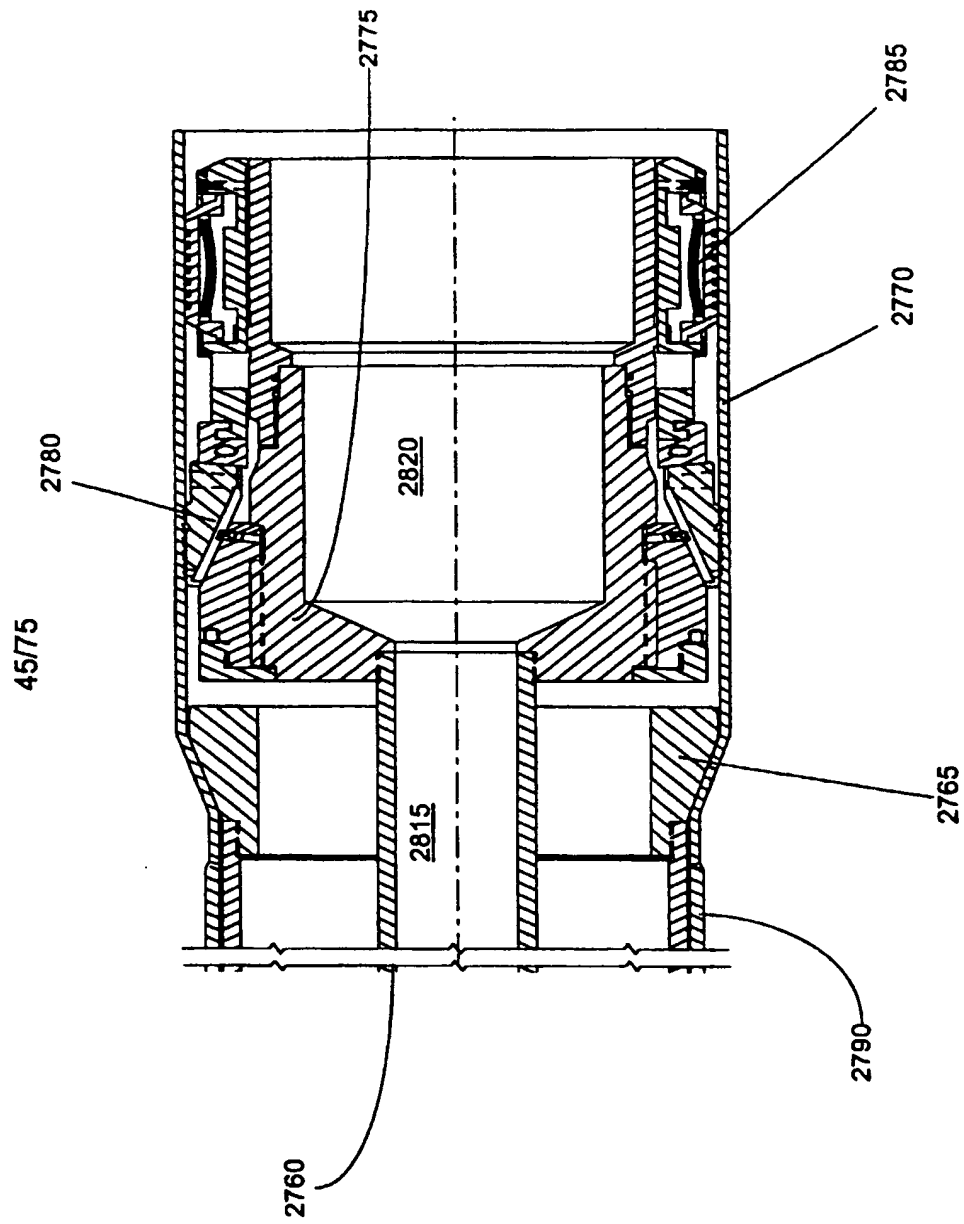


FIGURE 19b

2700

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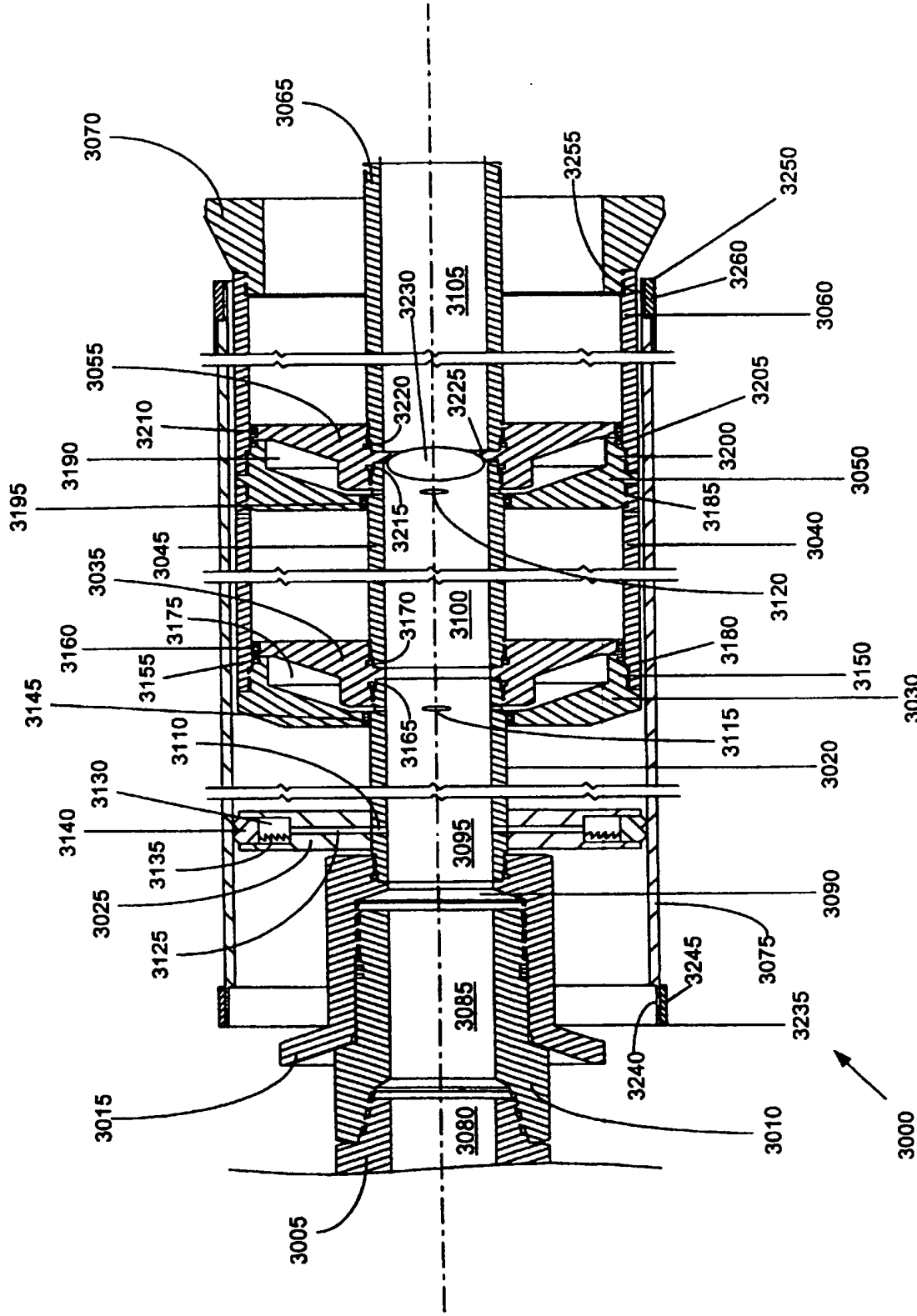


FIGURE 20

As illustrated in Fig. 11e, engagement of the wiper dart 1395 with the wiper plug 1350 causes the wiper plug 1350 to decouple from the mandrel 1305. The wiper dart 1395 and wiper plug 1350 then preferably will lodge in the fluid passage 1330, thereby blocking fluid flow through the fluid passage 1330, and fluidically isolating the interior region 1370 of the tubular member 1310 from the annular region 1390. The non hardenable fluidic material 1381 is then pumped into the interior region 1370 causing the interior region 1370 to pressurize. Once the interior region 1370 becomes sufficiently pressurized, the tubular member 1310 is extruded off of the expandable mandrel 1305. During the extrusion process, the expandable mandrel 1305 is raised out of the expanded portion of the tubular member 1310 by the support member 1345.

The wiper dart 1395 is preferably placed into the fluid passage 1320 by introducing the wiper dart 1395 into the fluid passage 1320 at a surface location in a conventional manner. The wiper dart 1395 may comprise any number of conventional commercially available devices from plugging a fluid passage such as, for example, Multiple Stage Cementer latch-down plugs, Omega latch-down plugs or three wiper latch-down plug/dart modified in accordance with the teachings of the present disclosure. The wiper dart 1395 comprises a three wiper latch-down plug modified to latch and seal in the Multiple Stage Cementer latch down plug 1350. The three wiper latch-down plug is available from Halliburton Energy Services in Dallas, TX.

After blocking the fluid passage 1330 using the wiper plug 1330 and wiper dart 1395, the non hardenable fluidic material 1381 may be pumped into the interior region 1370 at pressures and flow rates ranging, for example, from approximately 0 to 5000 psi and 0 to 1,500 gallons/min in order to optimally extrude the tubular member 1310 off of the mandrel 1305. In this manner, the amount of hardenable fluidic material within the interior of the tubular member 1310 is minimized.

After blocking the fluid passage 1330, the non hardenable fluidic material 1381 is preferably pumped into the interior region 1370 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to optimally provide operating pressures to maintain the expansion process at rates

sufficient to permit adjustments to be made in operating parameters during the extrusion process.

For typical tubular members 1310, the extrusion of the tubular member 1310 off of the expandable mandrel 1305 will begin when the pressure of the interior region 1370 reaches, for example, approximately 500 to 9,000 psi. The extrusion of the tubular member 1310 off of the expandable mandrel 1305 is a function of the tubular member diameter, wall thickness of the tubular member, geometry of the mandrel, the type of lubricant, the composition of the shoe and tubular member, and the yield strength of the tubular member. The optimum flow rate and operating pressures are preferably determined using conventional empirical methods.

During the extrusion process, the expandable mandrel 1305 may be raised out of the expanded portion of the tubular member 1310 at rates ranging, for example, from about 0 to 5 ft/sec. During the extrusion process, the expandable mandrel 1305 may be raised out of the expanded portion of the tubular member 1310 at rates ranging from about 0 to 2 ft/sec in order to optimally provide an efficient process, optimally permit operator adjustment of operation parameters, and ensure optimal completion of the extrusion process before curing of the material 1380.

When the upper end portion 1355 of the tubular member 1310 is extruded off of the expandable mandrel 1305, the outer surface of the upper end portion 1355 of the tubular member 1310 will preferably contact the interior surface of the lower end portion of the casing 1215 to form a fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50 to 20,000 psi. The contact pressure of the overlapping joint ranges from approximately 400 to 10,000 psi in order to optimally provide contact pressure sufficient to ensure annular sealing and provide enough resistance to withstand typical tensile and compressive loads. The sealing members 1340 will ensure an adequate fluidic and gaseous seal in the overlapping joint.

The operating pressure and flow rate of the non hardenable fluidic material 1381 is controllably ramped down when the expandable mandrel 1305 reaches the upper end portion 1355 of the tubular member 1310. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 1310 off

of the expandable mandrel 1305 can be minimized. The operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the mandrel 1305 has completed approximately all but about 5 feet of the extrusion process.

5 Alternatively, or in combination, a shock absorber is provided in the support member 1345 in order to absorb the shock caused by the sudden release of pressure.

 Alternatively, or in combination, a mandrel catching structure is provided in the upper end portion 1355 of the tubular member 1310 in order to catch or at least decelerate the mandrel 1305.

10 Once the extrusion process is completed, the expandable mandrel 1305 is removed from the wellbore 1200. Either before or after the removal of the expandable mandrel 1305, the integrity of the fluidic seal of the overlapping joint between the upper portion 1355 of the tubular member 1310 and the lower portion of the casing 1215 is tested using conventional methods. If the fluidic seal of the
15 overlapping joint between the upper portion 1355 of the tubular member 1310 and the lower portion of the casing 1215 is satisfactory, then the uncured portion of the material 1380 within the expanded tubular member 1310 is then removed in a conventional manner. The material 1380 within the annular region 1390 is then allowed to cure.

20 As illustrated in Fig. 11f, preferably any remaining cured material 1380 within the interior of the expanded tubular member 1310 is then removed in a conventional manner using a conventional drill string. The resulting new section of casing 1400 includes the expanded tubular member 1310 and an outer annular layer 1405 of cured material 305. The bottom portion of the apparatus 1300 comprising the shoe
25 1315 may then be removed by drilling out the shoe 1315 using conventional drilling methods.

 Referring now to Figs. 12 and 13, a wellhead system 1500 formed using one or more of the apparatus and processes described above with reference to Figs. 1-11f will be described. The wellhead system 1500 preferably includes a conventional
30 Christmas tree/drilling spool assembly 1505, a thick wall casing 1510, an annular

body of cement 1515, an outer casing 1520, an annular body of cement 1525, an intermediate casing 1530, and an inner casing 1535.

The Christmas tree/drilling spool assembly 1505 may comprise any number of conventional Christmas tree/drilling spool assemblies such as, for example, the SS-
5 15 Subsea Wellhead System, Spool Tree Subsea Production System or the Compact Wellhead System available from suppliers such as Dril-Quip, Cameron or Breda, modified in accordance with the teachings of the present disclosure. The drilling spool assembly 1505 is preferably operably coupled to the thick wall casing 1510 and/or the outer casing 1520. The assembly 1505 may be coupled to the thick wall
10 casing 1510 and/or outer casing 1520, for example, by welding, a threaded connection or made from single stock. The assembly 1505 is coupled to the thick wall casing 1510 and/or outer casing 1520 by welding.

The thick wall casing 1510 is positioned in the upper end of a wellbore 1540. At least a portion of the thick wall casing 1510 extends above the surface 1545 in
15 order to optimally provide easy access and attachment to the Christmas tree/drilling spool assembly 1505. The thick wall casing 1510 is preferably coupled to the Christmas tree/drilling spool assembly 1505, the annular body of cement 1515, and the outer casing 1520.

The thick wall casing 1510 may comprise any number of conventional
20 commercially available high strength wellbore casings such as, for example, Oilfield Country Tubular Goods, titanium tubing or stainless steel tubing. The thick wall casing 1510 comprises Oilfield Country Tubular Goods available from various foreign and domestic steel mills. The thick wall casing 1510 has a yield strength of about 40,000 to 135,000 psi in order to optimally provide maximum burst, collapse,
25 and tensile strengths. The thick wall casing 1510 has a failure strength in excess of about 5,000 to 20,000 psi in order to optimally provide maximum operating capacity and resistance to degradation of capacity after being drilled through for an extended time period.

The annular body of cement 1515 provides support for the thick wall casing
30 1510. The annular body of cement 1515 may be provided using any number of conventional processes for forming an annular body of cement in a wellbore. The

annular body of cement 1515 may comprise any number of conventional cement mixtures.

The outer casing 1520 is coupled to the thick wall casing 1510. The outer casing 1520 may be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. The outer casing 1520 comprises any one of the expandable tubular members described above with reference to Figs. 1-11f.

The outer casing 1520 is coupled to the thick wall casing 1510 by expanding the outer casing 1520 into contact with at least a portion of the interior surface of the thick wall casing 1510 using any one of the processes and apparatus described above with reference to Figs. 1-11f. Substantially all of the overlap of the outer casing 1520 with the thick wall casing 1510 contacts with the interior surface of the thick wall casing 1510. The contact pressure of the interface between the outer casing 1520 and the thick wall casing 1510 may range, for example, from about 500 to 10,000 psi. The contact pressure between the outer casing 1520 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the pressure activated sealing members and to ensure that the overlapping joint will optimally withstand typical extremes of tensile and compressive loads that are experienced during drilling and production operations.

As illustrated in Fig. 13, The upper end of the outer casing 1520 includes one or more sealing members 1550 that provide a gaseous and fluidic seal between the expanded outer casing 1520 and the interior wall of the thick wall casing 1510. The sealing members 1550 may comprise any number of conventional commercially available seals such as, for example, lead, plastic, rubber, Teflon or epoxy, modified in accordance with the teachings of the present disclosure. The sealing members 1550 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal and a load bearing interference fit between the tubular members. The contact pressure of the interface between the thick wall casing 1510 and the outer casing 1520 ranges from about 500 to 10,000 psi in order to optimally activate the sealing members 1550 and also

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optimally ensure that the joint will withstand the typical operating extremes of tensile and compressive loads during drilling and production operations.

The outer casing 1520 and the thick walled casing 1510 are combined in one unitary member.

5 The annular body of cement 1525 provides support for the outer casing 1520. The annular body of cement 1525 is provided using any one of the apparatus and processes described above with reference to Figs. 1-11f.

10 The intermediate casing 1530 may be coupled to the outer casing 1520 or the thick wall casing 1510. The intermediate casing 1530 is coupled to the thick wall casing 1510. The intermediate casing 1530 may be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. The intermediate casing 1530 comprises any one of the expandable tubular members described above with reference to Figs. 1-11f.

15 The intermediate casing 1530 is coupled to the thick wall casing 1510 by expanding at least a portion of the intermediate casing 1530 into contact with the interior surface of the thick wall casing 1510 using any one of the processes and apparatus described above with reference to Figs. 1-11f. The entire length of the overlap of the intermediate casing 1530 with the thick wall casing 1510 contacts the
20 inner surface of the thick wall casing 1510. The contact pressure of the interface between the intermediate casing 1530 and the thick wall casing 1510 may range, for example from about 500 to 10,000 psi. The contact pressure between the intermediate casing 1530 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the pressure activated sealing members and
25 to optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads experienced during drilling and production operations.

As illustrated in Fig. 13, The upper end of the intermediate casing 1530 includes one or more sealing members 1560 that provide a gaseous and fluidic seal between the expanded end of the intermediate casing 1530 and the interior wall of
30 the thick wall casing 1510. The sealing members 1560 may comprise any number of conventional commercially available seals such as, for example, plastic, lead,

rubber, Teflon or epoxy, modified in accordance with the teachings of the present disclosure. The sealing members 1560 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in order to optimally provide a hydraulic seal and a load bearing interference fit between the tubular members.

5 The contact pressure of the interface between the expanded end of the intermediate casing 1530 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the sealing members 1560 and also optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads that are experienced during drilling and production
10 operations.

 The inner casing 1535 may be coupled to the outer casing 1520 or the thick wall casing 1510. The inner casing 1535 is coupled to the thick wall casing 1510. The inner casing 1535 may be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings
15 of the present disclosure. The inner casing 1535 comprises any one of the expandable tubular members described above with reference to Figs. 1-11f.

 The inner casing 1535 is coupled to the outer casing 1520 by expanding at least a portion of the inner casing 1535 into contact with the interior surface of the thick wall casing 1510 using any one of the processes and apparatus described above
20 with reference to Figs. 1-11f. The entire length of the overlap of the inner casing 1535 with the thick wall casing 1510 and intermediate casing 1530 contacts the inner surfaces of the thick wall casing 1510 and intermediate casing 1530. The contact pressure of the interface between the inner casing 1535 and the thick wall casing 1510 may range, for example from about 500 to 10,000 psi. The contact
25 pressure between the inner casing 1535 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the pressure activated sealing members and to ensure that the joint will withstand typical extremes of tensile and compressive loads that are commonly experienced during drilling and production operations.

30 As illustrated in Fig. 13, The upper end of the inner casing 1535 includes one or more sealing members 1570 that provide a gaseous and fluidic seal between the

expanded end of the inner casing 1535 and the interior wall of the thick wall casing 1510. The sealing members 1570 may comprise any number of conventional commercially available seals such as, for example, lead, plastic, rubber, Teflon or epoxy, modified in accordance with the teachings of the present disclosure. The
5 sealing members 1570 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal and a load bearing interference fit. The contact pressure of the interface between the expanded end of the inner casing 1535 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the sealing members 1570 and
10 also to optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads that are experienced during drilling and production operations.

The inner casings, 1520, 1530 and 1535, may be coupled to a previously positioned tubular member that is in turn coupled to the outer casing 1510. More
15 generally, the present preferred embodiments may be used to form a concentric arrangement of tubular members.

Referring now to Figures 14a, 14b, 14c, 14d, 14e and 14f, a method and apparatus for forming a mono-diameter well casing within a subterranean formation will now be described.

20 As illustrated in Fig. 14a, a wellbore 1600 is positioned in a subterranean formation 1605. A first section of casing 1610 is formed in the wellbore 1600. The first section of casing 1610 includes an annular outer body of cement 1615 and a tubular section of casing 1620. The first section of casing 1610 may be formed in the wellbore 1600 using conventional methods and apparatus. The first section of
25 casing 1610 is formed using one or more of the methods and apparatus described above with reference to Figs. 1-13 or below with reference to Figs. 14b-17b.

The annular body of cement 1615 may comprise any number of conventional commercially available cement, or other load bearing, compositions. Alternatively, the body of cement 1615 may be omitted or replaced with an epoxy mixture.

30 The tubular section of casing 1620 preferably includes an upper end 1625 and a lower end 1630. Preferably, the lower end 1625 of the tubular section of casing

1620 includes an outer annular recess 1635 extending from the lower end 1630 of the tubular section of casing 1620. In this manner, the lower end 1625 of the tubular section of casing 1620 includes a thin walled section 1640. An annular body 1645 of a compressible material is coupled to and at least partially positioned within the outer annular recess 1635. In this manner, the body of compressible material 1645 surrounds at least a portion of the thin walled section 1640.

The tubular section of casing 1620 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, automotive grade steel, carbon steel, low alloy steel, fiberglass or plastics. The tubular section of casing 1620 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills. The wall thickness of the thin walled section 1640 may range from about 0.125 to 1.5 inches. The wall thickness of the thin walled section 1640 ranges from 0.25 to 1.0 inches in order to optimally provide burst strength for typical operational conditions while also minimizing resistance to radial expansion. The axial length of the thin walled section 1640 may range from about 120 to 2400 inches. The axial length of the thin walled section 1640 ranges from about 240 to 480 inches.

The annular body of compressible material 1645 helps to minimize the radial force required to expand the tubular casing 1620 in the overlap with the tubular member 1715, helps to create a fluidic seal in the overlap with the tubular member 1715, and helps to create an interference fit sufficient to permit the tubular member 1715 to be supported by the tubular casing 1620. The annular body of compressible material 1645 may comprise any number of commercially available compressible materials such as, for example, epoxy, rubber, Teflon, plastics or lead tubes. The annular body of compressible material 1645 comprises StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal in the overlapped joint while also having compliance to thereby minimize the radial force required to expand the tubular casing. The wall thickness of the annular body of compressible material 1645 may range from about 0.05 to 0.75 inches. The wall thickness of the annular body of compressible material 1645 ranges from about 0.1 to 0.5 inches in order to optimally provide a large compressible zone, minimize the

radial forces required to expand the tubular casing, provide thickness for casing strings to provide contact with the inner surface of the wellbore upon radial expansion, and provide an hydraulic seal.

As illustrated in Fig. 14b, in order to extend the wellbore 1600 into the subterranean formation 1605, a drill string is used in a well known manner to drill out material from the subterranean formation 1605 to form a new wellbore section 1650. The diameter of the new section 1650 is preferably equal to or greater than the inner diameter of the tubular section of casing 1620.

As illustrated in Fig. 14c, an apparatus 1700 for forming a mono-diameter wellbore casing in a subterranean formation is then positioned in the new section 1650 of the wellbore 1600. The apparatus 1700 preferably includes a support member 1705, an expandable mandrel or pig 1710, a tubular member 1715, a shoe 1720, slips 1725, a fluid passage 1730, one or more fluid passages 1735, a fluid passage 1740, a first compressible annular body 1745, a second compressible annular body 1750, and a pressure chamber 1755.

The support member 1705 supports the apparatus 1700 within the wellbore 1600. The support member 1705 is coupled to the mandrel 1710, the tubular member 1715, the shoe 1720, and the slips 1725. The support member 1075 preferably comprises a substantially hollow tubular member. The fluid passage 1730 is positioned within the support member 1705. The fluid passages 1735 fluidically couple the fluid passage 1730 with the pressure chamber 1755. The fluid passage 1740 fluidically couples the fluid passage 1730 with the region outside of the apparatus 1700.

The support member 1705 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, low alloy steel, carbon steel, 13 chromium steel, fiberglass, or other high strength materials. The support member 1705 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide operational strength and facilitate the use of other standard oil exploration handling equipment. At least a portion of the support member 1705 comprises coiled tubing or a drill pipe. The support member 1705

includes a load shoulder 1820 for supporting the mandrel 1710 when the pressure chamber 1755 is unpressurized.

The mandrel 1710 is supported by and slidingly coupled to the support member 1705 and the shoe 1720. The mandrel 1710 preferably includes an upper portion 1760 and a lower portion 1765. Preferably, the upper portion 1760 of the mandrel 1710 and the support member 1705 together define the pressure chamber 1755. Preferably, the lower portion 1765 of the mandrel 1710 includes an expansion member 1770 for radially expanding the tubular member 1715.

The upper portion 1760 of the mandrel 1710 includes a tubular member 1775 having an inner diameter greater than an outer diameter of the support member 1705. In this manner, an annular pressure chamber 1755 is defined by and positioned between the tubular member 1775 and the support member 1705. The top 1780 of the tubular member 1775 preferably includes a bearing and a seal for sealing and supporting the top 1780 of the tubular member 1775 against the outer surface of the support member 1705. The bottom 1785 of the tubular member 1775 preferably includes a bearing and seal for sealing and supporting the bottom 1785 of the tubular member 1775 against the outer surface of the support member 1705 or shoe 1720. In this manner, the mandrel 1710 moves in an axial direction upon the pressurization of the pressure chamber 1755.

The lower portion 1765 of the mandrel 1710 preferably includes an expansion member 1770 for radially expanding the tubular member 1715 during the pressurization of the pressure chamber 1755. The expansion member is expandable in the radial direction. The inner surface of the lower portion 1765 of the mandrel 1710 mates with and slides with respect to the outer surface of the shoe 1720. The outer diameter of the expansion member 1770 may range from about 90 to 100 % of the inner diameter of the tubular casing 1620. The outer diameter of the expansion member 1770 ranges from about 95 to 99 % of the inner diameter of the tubular casing 1620. The expansion member 1770 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, ceramics, tungsten carbide, titanium or other high strength alloys. The

expansion member 1770 is fabricated from D2 machine tool steel in order to optimally provide high strength and abrasion resistance.

The tubular member 1715 is coupled to and supported by the support member 1705 and slips 1725. The tubular member 1715 includes an upper portion 1790 and
5 a lower portion 1795.

The upper portion 1790 of the tubular member 1715 preferably includes an inner annular recess 1800 that extends from the upper portion 1790 of the tubular member 1715. In this manner, at least a portion of the upper portion 1790 of the tubular member 1715 includes a thin walled section 1805. The first compressible
10 annular member 1745 is preferably coupled to and supported by the outer surface of the upper portion 1790 of the tubular member 1715 in opposing relation to the thin wall section 1805.

The lower portion 1795 of the tubular member 1715 preferably includes an outer annular recess 1810 that extends from the lower portion 1790 of the tubular
15 member 1715. In this manner, at least a portion of the lower portion 1795 of the tubular member 1715 includes a thin walled section 1815. The second compressible annular member 1750 is coupled to and at least partially supported within the outer annular recess 1810 of the upper portion 1790 of the tubular member 1715 in opposing relation to the thin wall section 1815.

20 The tubular member 1715 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, low alloy steel, carbon steel, automotive grade steel, fiberglass, 13 chrome steel, other high strength material, or high strength plastics. The tubular member 1715 is fabricated from oilfield country tubular goods available
25 from various foreign and domestic steel mills in order to optimally provide operational strength.

The shoe 1720 is supported by and coupled to the support member 1705. The shoe 1720 preferably comprises a substantially hollow tubular member. The wall thickness of the shoe 1720 is greater than the wall thickness of the support member
30 1705 in order to optimally provide increased radial support to the mandrel 1710. The shoe 1720 may be fabricated from any number of conventional commercially

available materials such as, for example, oilfield country tubular goods, stainless steel, automotive grade steel, low alloy steel, carbon steel, or high strength plastics. The shoe 1720 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide matching
5 operational strength throughout the apparatus.

The slips 1725 are coupled to and supported by the support member 1705. The slips 1725 removably support the tubular member 1715. In this manner, during the radial expansion of the tubular member 1715, the slips 1725 help to maintain the tubular member 1715 in a substantially stationary position by preventing upward
10 movement of the tubular member 1715.

The slips 1725 may comprise any number of conventional commercially available slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips, or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. The slips 1725 comprise RTTS packer
15 tungsten carbide mechanical slips available from Halliburton Energy Services. The slips 1725 are adapted to support axial forces ranging from about 0 to 750,000 lbf.

The fluid passage 1730 conveys fluidic materials from a surface location into the interior of the support member 1705, the pressure chamber 1755, and the region exterior of the apparatus 1700. The fluid passage 1730 is fluidically coupled to the
20 pressure chamber 1755 by the fluid passages 1735. The fluid passage 1730 is fluidically coupled to the region exterior to the apparatus 1700 by the fluid passage 1740.

The fluid passage 1730 is adapted to convey fluidic materials such as, for example, cement, epoxy, drilling muds, slag mix, water or drilling gasses. The fluid
25 passage 1730 is adapted to convey fluidic materials at flow rate and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi. in order to optimally provide flow rates and operational pressures for the radial expansion processes.

The fluid passages 1735 convey fluidic material from the fluid passage 1730 to
30 the pressure chamber 1755. The fluid passage 1735 is adapted to convey fluidic materials such as, for example, cement, epoxy, drilling muds, water or drilling

gasses. The fluid passage 1735 is adapted to convey fluidic materials at flow rate and pressures ranging from about 0 to 500 gallons/minute and 0 to 9,000 psi. in order to optimally provide operating pressures and flow rates for the various expansion processes.

5 The fluid passage 1740 conveys fluidic materials from the fluid passage 1730 to the region exterior to the apparatus 1700. The fluid passage 1740 is adapted to convey fluidic materials such as, for example, cement, epoxy, drilling muds, water or drilling gasses. The fluid passage 1740 is adapted to convey fluidic materials at
10 flow rate and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi. in order to optimally provide operating pressures and flow rates for the various radial expansion processes.

 The fluid passage 1740 is adapted to receive a plug or other similar device for sealing the fluid passage 1740. In this manner, the pressure chamber 1755 may be pressurized.

15 The first compressible annular body 1745 is coupled to and supported by an exterior surface of the upper portion 1790 of the tubular member 1715. The first compressible annular body 1745 is positioned in opposing relation to the thin walled section 1805 of the tubular member 1715.

 The first compressible annular body 1745 helps to minimize the radial force
20 required to expand the tubular member 1715 in the overlap with the tubular casing 1620, helps to create a fluidic seal in the overlap with the tubular casing 1620, and helps to create an interference fit sufficient to permit the tubular member 1715 to be supported by the tubular casing 1620. The first compressible annular body 1745 may comprise any number of commercially available compressible materials such
25 as, for example, epoxy, rubber, Teflon, plastics, or hollow lead tubes. The first compressible annular body 1745 comprises StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal, and compressibility to minimize the radial expansion force.

 The wall thickness of the first compressible annular body 1745 may range
30 from about 0.05 to 0.75 inches. The wall thickness of the first compressible annular body 1745 ranges from about 0.1 to 0.5 inches in order to optimally (1) provide a

large compressible zone, (2) minimize the required radial expansion force, (3) transfer the radial force to the tubular casings. As a result, overall the outer diameter of the tubular member 1715 is approximately equal to the overall inner diameter of the tubular member 1620.

5 The second compressible annular body 1750 is coupled to and at least partially supported within the outer annular recess 1810 of the tubular member 1715. The second compressible annular body 1750 is positioned in opposing relation to the thin walled section 1815 of the tubular member 1715.

10 The second compressible annular body 1750 helps to minimize the radial force required to expand the tubular member 1715 in the overlap with another tubular member, helps to create a fluidic seal in the overlap of the tubular member 1715 with another tubular member, and helps to create an interference fit sufficient to permit another tubular member to be supported by the tubular member 1715. The second compressible annular body 1750 may comprise any number of commercially
15 available compressible materials such as, for example, epoxy, rubber, Teflon, plastics or hollow lead tubing. The first compressible annular body 1750 comprises StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal in the overlapped joint, and compressibility that minimizes the radial expansion force.

20 The wall thickness of the second compressible annular body 1750 may range from about 0.05 to 0.75 inches. The wall thickness of the second compressible annular body 1750 ranges from about 0.1 to 0.5 inches in order to optimally provide a large compressible zone, and minimize the radial force required to expand the tubular member 1715 during subsequent radial expansion operations.

25 The outside diameter of the second compressible annular body 1750 is adapted to provide a seal against the surrounding formation thereby eliminating the need for an outer annular body of cement.

30 The pressure chamber 1755 is fluidically coupled to the fluid passage 1730 by the fluid passages 1735. The pressure chamber 1755 is preferably adapted to receive fluidic materials such as, for example, drilling muds, water or drilling gases. The pressure chamber 1755 is adapted to receive fluidic materials at flow rate and

fluidic material 1825 comprises a non-hardenable fluidic material such as, for example, drilling mud or drilling gases in order to optimally provide pressurization of the pressure chamber 1755.

5 The fluidic material 1840 may be pumped into the fluid passage 1730 at operating pressures and flow rates ranging, for example, from about 0 to 9,000 psi and 0 to 500 gallons/minute. The fluidic material 1840 is pumped into the fluid passage 1730 at operating pressures and flow rates ranging from about 500 to 5,000 psi and 0 to 500 gallons/minute in order to optimally provide operating pressures and flow rates for radial expansion.

10 The fluidic material 1840 pumped into the fluid passage 1730 passes through the fluid passages 1735 and into the pressure chamber 1755. Continued pumping of the fluidic material 1840 pressurizes the pressure chamber 1755. The pressurization of the pressure chamber 1755 causes the mandrel 1710 to move relative to the support member 1705 in the direction indicated by the arrows 1845. In this manner,
15 the mandrel 1710 will cause the tubular member 1715 to expand in the radial direction.

During the radial expansion process, the tubular member 1715 is prevented from moving in an upward direction by the slips 1725. A length of the tubular member 1715 is then expanded in the radial direction through the pressurization of
20 the pressure chamber 1755. The length of the tubular member 1715 that is expanded during the expansion process will be proportional to the stroke length of the mandrel 1710. Upon the completion of a stroke, the operating pressure of the pressure chamber 1755 is then reduced and the mandrel 1710 drops to its rest position with the tubular member 1715 supported by the mandrel 1715. The position of the support
25 member 1705 may be adjusted throughout the radial expansion process in order to maintain the overlapping relationship between the thin walled sections, 1640 and 1805, of the tubular casing 1620 and tubular member 1715. The stroking of the mandrel 1710 is then repeated, as necessary, until the thin walled section 1805 of the tubular member 1715 is expanded into the thin walled section 1640 of the tubular
30 casing 1620.

During the final stroke of the mandrel 1710, the slips 1725 are positioned as close as possible to the thin walled section 1805 of the tubular member 1715 in order minimize slippage between the tubular member 1715 and tubular casing 1620 at the end of the radial expansion process. Alternatively, or in addition, the outside diameter of the first compressive annular member 1745 is selected to ensure sufficient interference fit with the tubular casing 1620 to prevent axial displacement of the tubular member 1715 during the final stroke. Alternatively, or in addition, the outside diameter of the second compressive annular body 1750 is large enough to provide an interference fit with the inside walls of the wellbore 1600 at an earlier point in the radial expansion process so as to prevent further axial displacement of the tubular member 1715. In this final alternative, the interference fit is preferably selected to permit expansion of the tubular member 1715 by pulling the mandrel 1710 out of the wellbore 1600, without having to pressurize the pressure chamber 1755.

During the radial expansion process, the pressurized areas of the apparatus 1700 are limited to the fluid passages 1730 within the support member 1705 and the pressure chamber 1755 within the mandrel 1710. No fluid pressure acts directly on the tubular member 1715. This permits the use of operating pressures higher than the tubular member 1715 could normally withstand.

Once the tubular member 1715 has been completely expanded off of the mandrel 1710, the support member 1705 and mandrel 1710 are removed from the wellbore 1600. The contact pressure between the deformed thin wall sections, 1640 and 1805, and compressible annular members, 1645 and 1745, ranges from about 400 to 10,000 psi in order to optimally support the tubular member 1715 using the tubular casing 1620.

In this manner, the tubular member 1715 is radially expanded into contact with the tubular casing 1620 by pressurizing the interior of the fluid passage 1730 and the pressure chamber 1755.

As illustrated in Fig. 14f, once the tubular member 1715 is completely expanded in the radial direction by the mandrel 1710, the support member 1705 and mandrel 1710 are removed from the wellbore 1600. The annular body of hardenable

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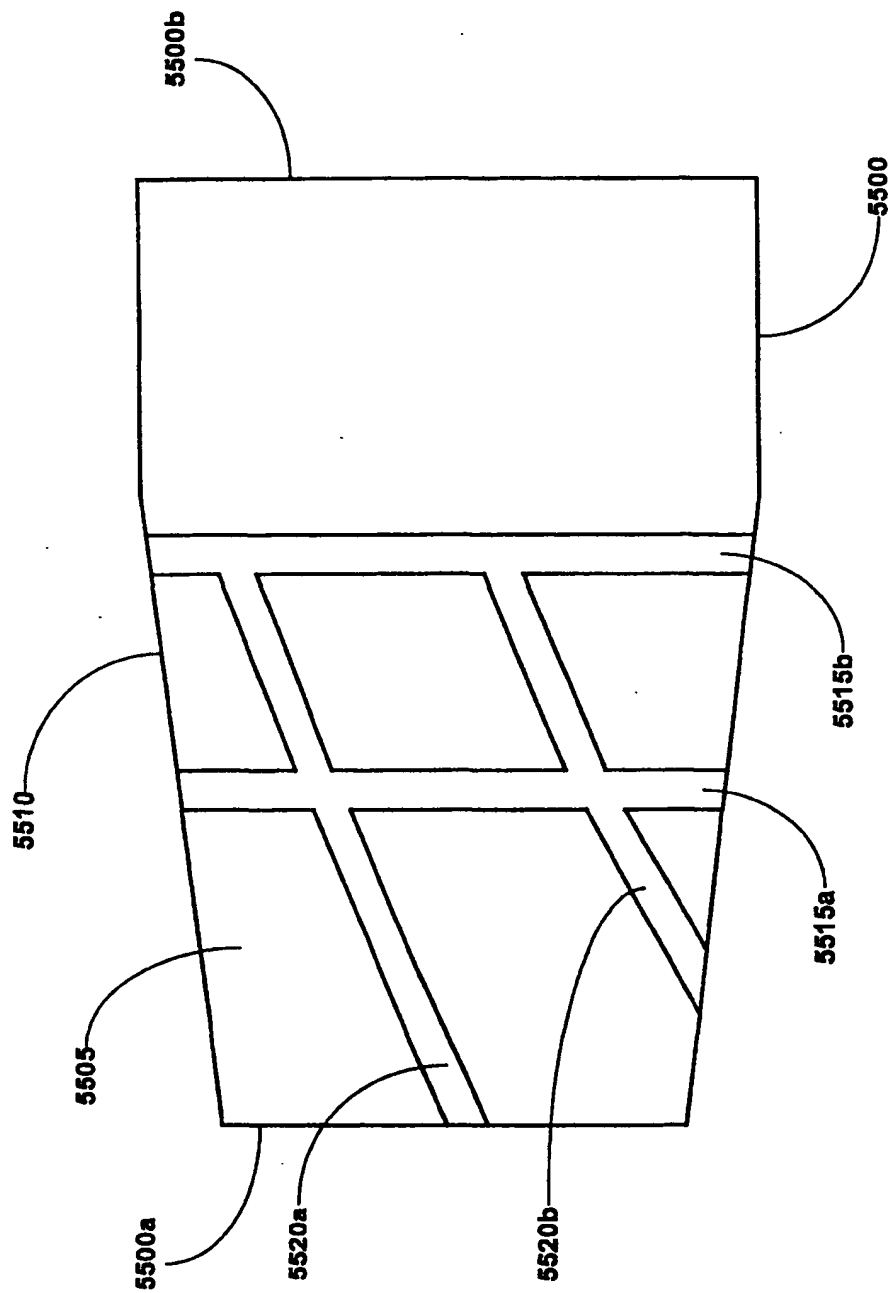


FIGURE 36

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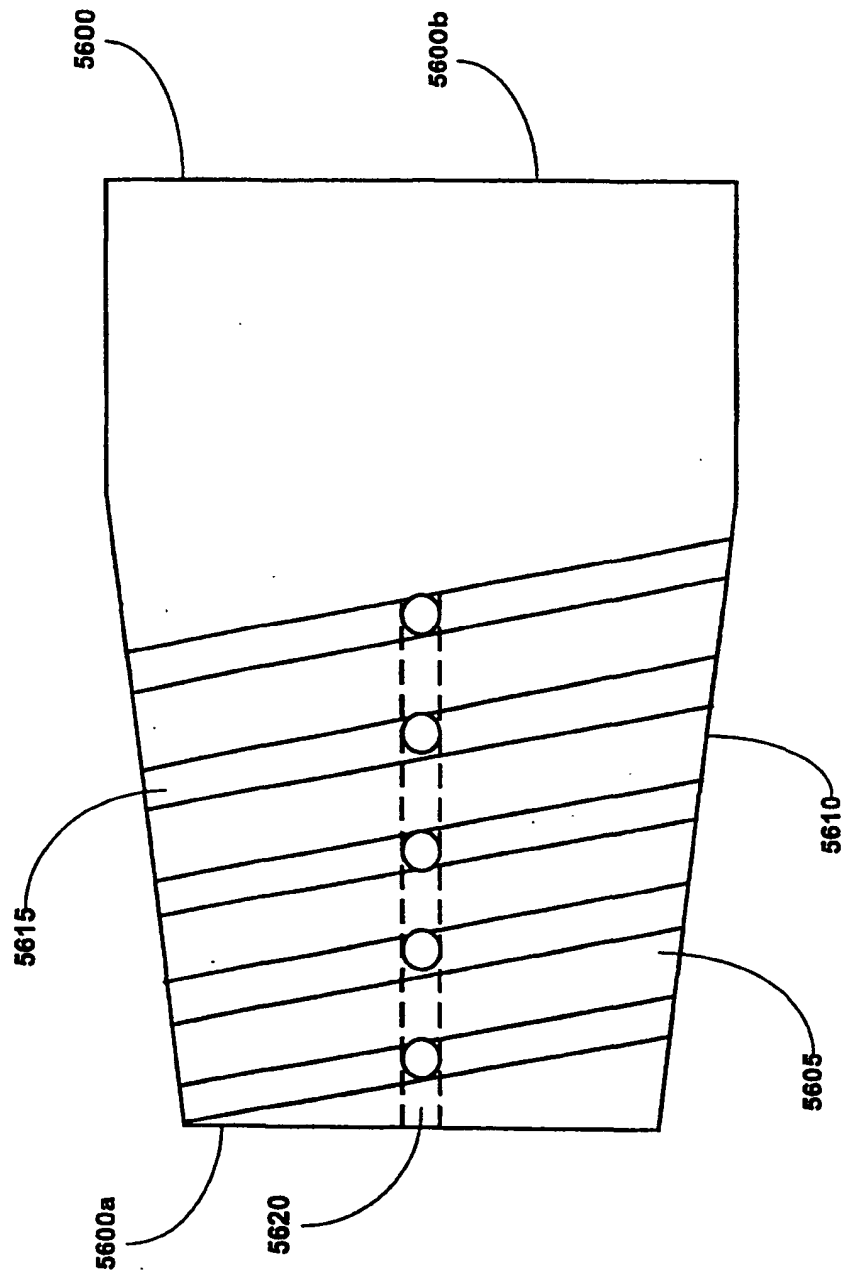


FIGURE 37

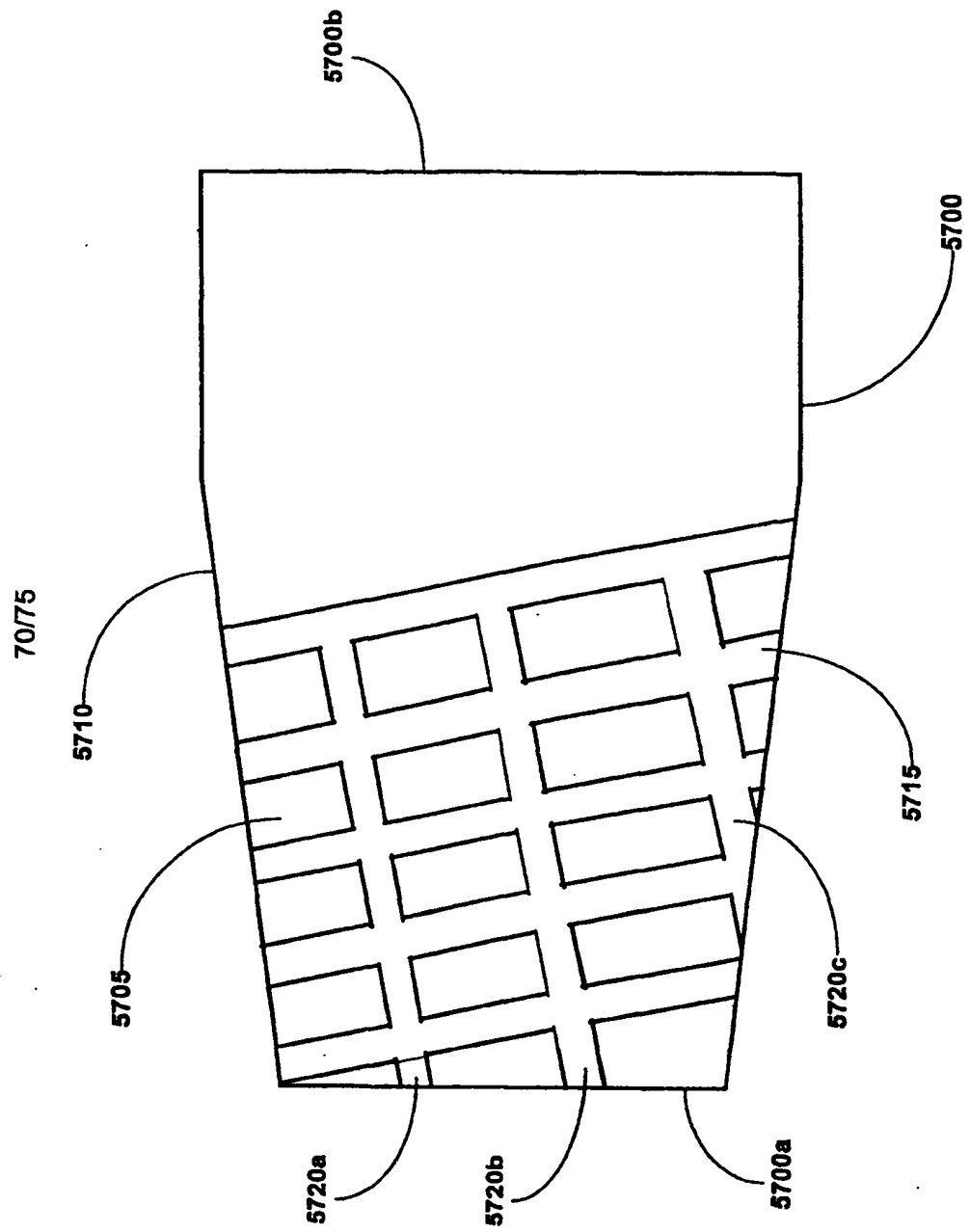


FIGURE 38

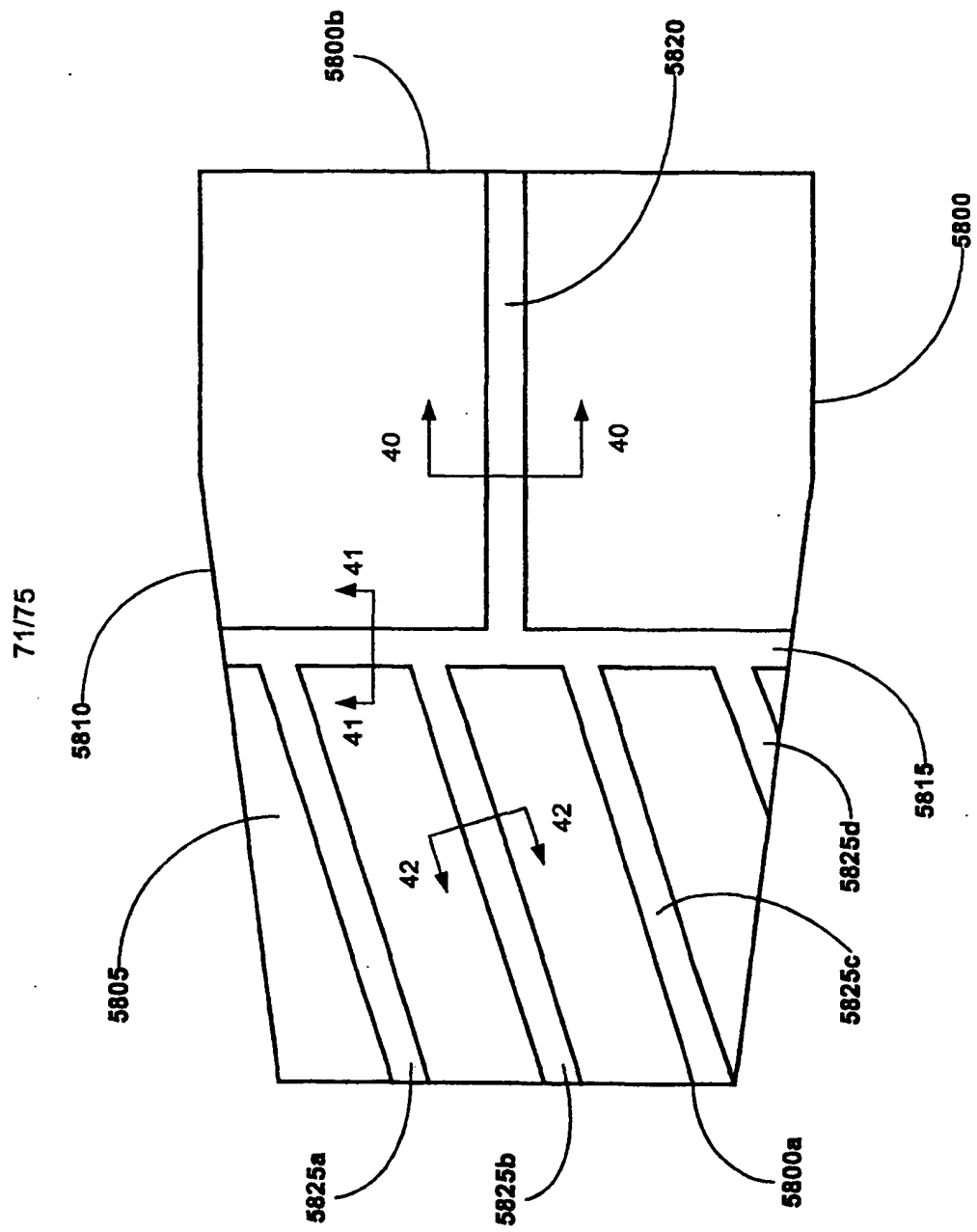


FIGURE 39

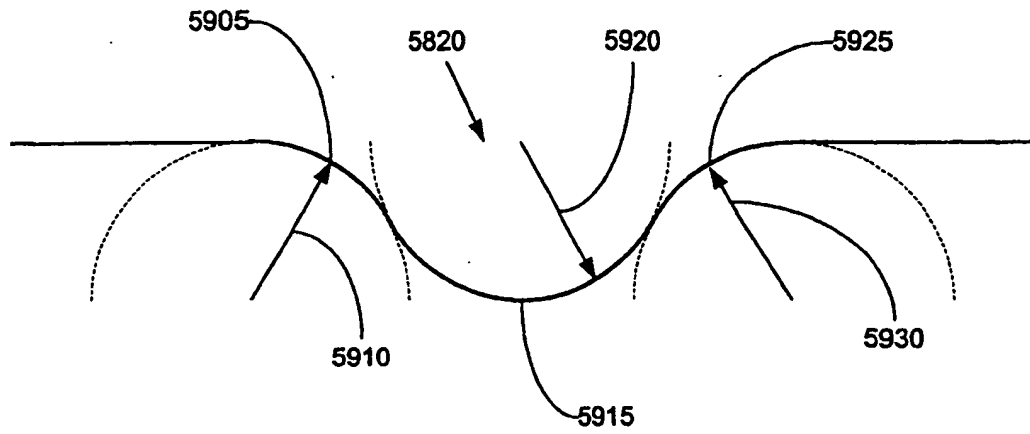


FIGURE 40

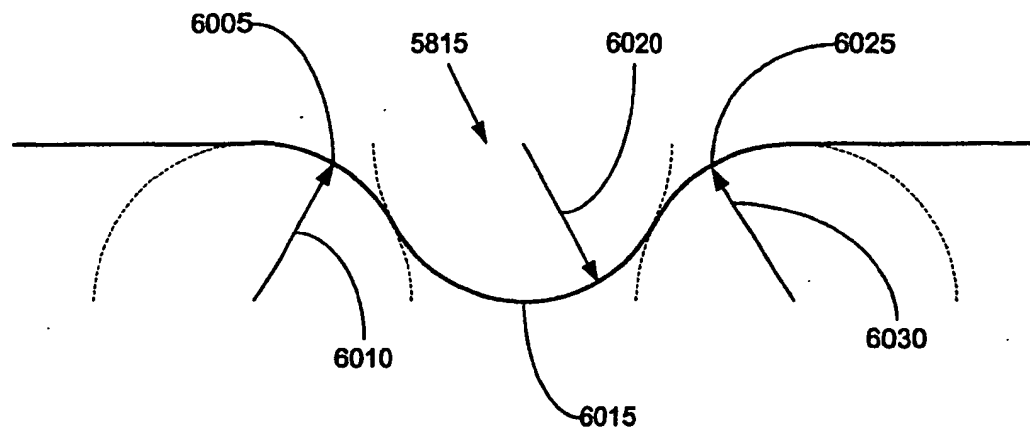


FIGURE 41

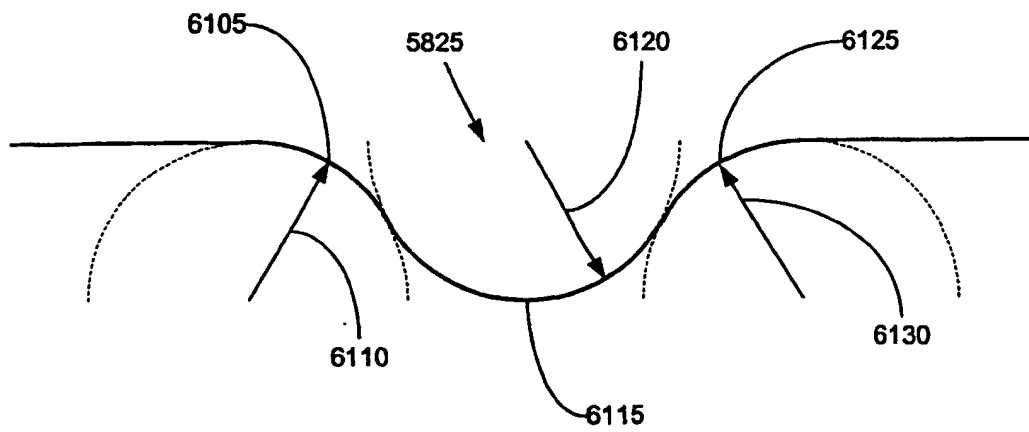


FIGURE 42

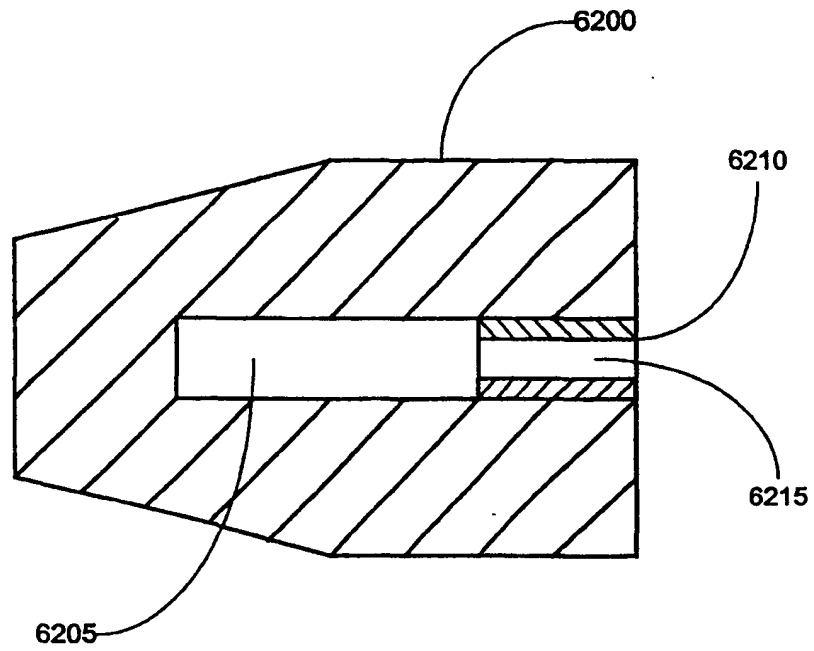


FIGURE 43

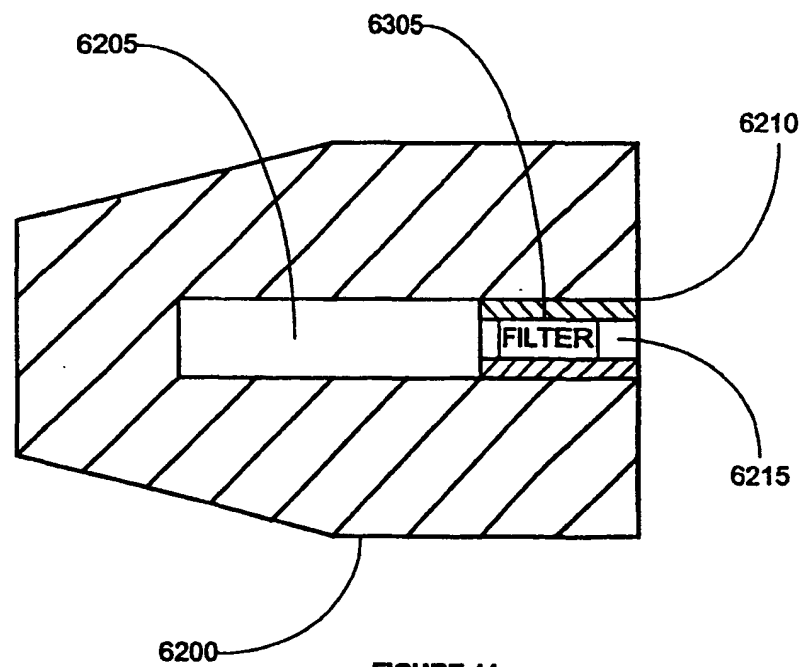


FIGURE 44

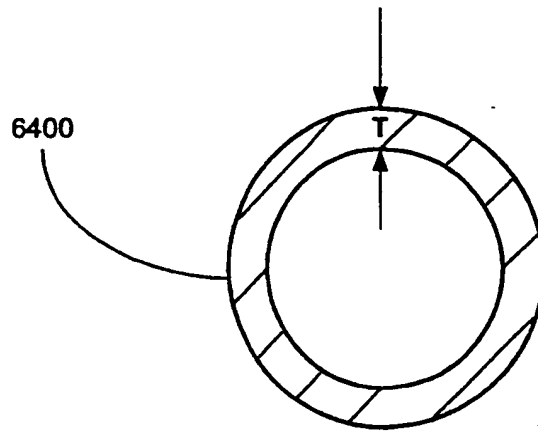


FIGURE 45

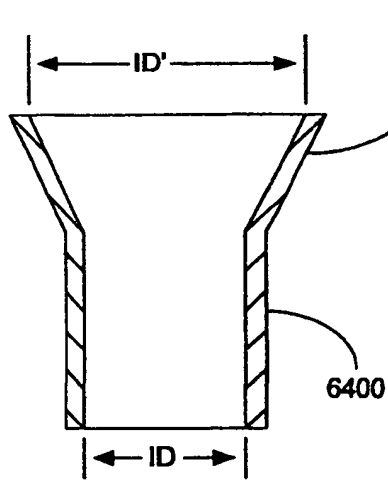


FIGURE 46

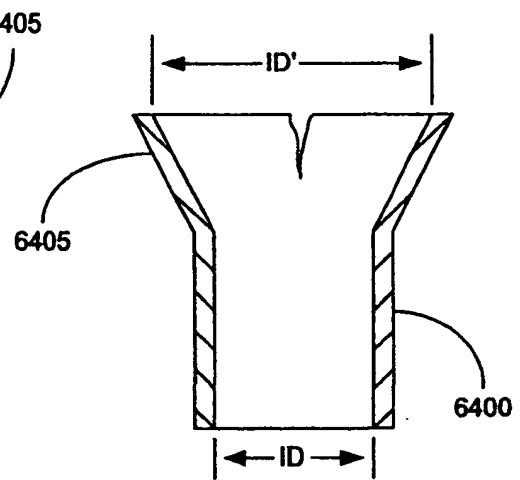


FIGURE 47

LUBRICATION AND SELF-CLEANING SYSTEM FOR EXPANSION MANDREL

Background of the Invention

This invention relates generally to wellbore casings, and in particular to
5 wellbore casings that are formed using expandable tubing.

Conventionally, when a wellbore is created, a number of casings are installed
in the borehole to prevent collapse of the borehole wall and to prevent undesired
outflow of drilling fluid into the formation or inflow of fluid from the formation into
the borehole. The borehole is drilled in intervals whereby a casing which is to be
10 installed in a lower borehole interval is lowered through a previously installed
casing of an upper borehole interval. As a consequence of this procedure the casing
of the lower interval is of smaller diameter than the casing of the upper interval.
Thus, the casings are in a nested arrangement with casing diameters decreasing in
downward direction. Cement annuli are provided between the outer surfaces of the
15 casings and the borehole wall to seal the casings from the borehole wall. As a
consequence of this nested arrangement a relatively large borehole diameter is
required at the upper part of the wellbore. Such a large borehole diameter involves
increased costs due to heavy casing handling equipment, large drill bits and
increased volumes of drilling fluid and drill cuttings. Moreover, increased drilling
20 rig time is involved due to required cement pumping, cement hardening, required
equipment changes due to large variations in hole diameters drilled in the course of
the well, and the large volume of cuttings drilled and removed.

Conventionally, at the surface end of the wellbore, a wellhead is formed that
typically includes a surface casing, a number of production and/or drilling spools,
25 valving, and a Christmas tree. Typically the wellhead further includes a concentric
arrangement of casings including a production casing and one or more intermediate
casings. The casings are typically supported using load bearing slips positioned
above the ground. The conventional design and construction of wellheads is
expensive and complex.

Conventionally, a wellbore casing cannot be formed during the drilling of a wellbore. Typically, the wellbore is drilled and then a wellbore casing is formed in the newly drilled section of the wellbore. This delays the completion of a well.

The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming wellbores and wellheads.

Summary Of The Invention

According to one aspect of the present invention, there is provided an expansion device for expanding a tubular member, comprising:

10 a housing including a tapered first end and a second end
one or more grooves formed in the outer surface of the tapered first end;
and
one or more axial flow passages fluidicly coupled to the or each groove;
wherein the or each groove comprises a spiral groove.

15 According to another aspect of the present invention, there is provided an expansion device for expanding a tubular member, comprising
a housing including a tapered first end and a second end;
one or more grooves formed in the outer surface of the tapered first end; and
one or more axial flow passages fluidicly coupled to the or each groove;
20 wherein the or each axial flow passage comprises an axial groove.

Preferably, there are a plurality of axial grooves which are spaced apart by at least 76.2 mm (3 inches) in the circumferential direction.

Preferably, the or each axial groove extends from the tapered first end of the body to the or each groove.

25 Preferably, the or each axial groove extends from the second end of the body to the or each groove.

Preferably, the or each axial groove extends from the tapered first end of the body to the second end of the body.

According to another aspect of the present invention, there is provided an expansion device for expanding a tubular member, comprising:

30 a housing including a tapered first end and a second end;

one or more grooves formed in the outer surface of the tapered first end;
one or more axial flow passages fluidically coupled to the or each groove;
wherein the or each axial flow passage is positioned within the housing of the
expansion device;

5 wherein the or each axial flow passage extends from the tapered first end of
the body to the or each groove.

Preferably, the or each flow passage extends from the tapered first end of the
body to the second end of the body.

Preferably, the or each flow passage extends from the second end of the body
10 to the or each groove.

Preferably, at least one of the or each axial flow passage includes an insert
having a restricted flow passage.

Preferably, at least one of the or each axial flow passage includes a filter.

Preferably, the cross sectional area of the or each groove is greater than the
15 cross sectional area of the or each axial flow passage.

Preferably, the cross-sectional area of the or each groove ranges from $129 \times 10^{-3} \text{ mm}^2$ to 32.26 mm^2 ($2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$).

Preferably, the cross-sectional area of the or each axial flow passage ranges
from $129 \times 10^{-3} \text{ mm}^2$ to 32.26 mm^2 ($2 \times 10^{-4} \text{ in}^2$ to $5 \times 10^{-2} \text{ in}^2$).

20 Preferably, the or each groove is concentrated in a trailing edge portion of the
tapered first end.

Preferably, the angle of inclination of the or each axial flow passage relative to
the longitudinal axis of the expansion device is greater than the angle of attack of the
first tapered end.

25 Preferably, the or each groove includes:

a flow channel having a first radius of curvature;

a first shoulder positioned on one side of the flow channel having a second
radius of curvature; and

a second shoulder positioned on the other side of the flow channel having a
30 third radius of curvature.

Preferably, the first, second and third radii of curvature are substantially equal.

Preferably, the or each axial flow passage includes:

a flow channel having a first radius of curvature;

a first shoulder positioned on one side of the flow channel having a second radius of curvature; and

5 a second shoulder positioned on the other side of the flow channel having a third radius of curvature.

Preferably, the first, second and third radii of curvature are substantially equal.

Preferably, the second radius of curvature is greater than the third radius of curvature.

10 Preferably, the expansion device is coupled to a tubular support member defining a first longitudinal passage extending therethrough.

Preferably, the tubular member comprises an expandable wellbore casing movably coupled to the tapered first end of the expansion device.

According to another aspect of the present invention, there is provided a
15 method of lubricating the interface between a tubular member and an expansion device having a first tapered end and a second end during the radial expansion of the tubular member by the expansion device, wherein the interface between the tubular member and the first tapered end of the expansion device includes one or more grooves formed in an outer surface, one or more axial flow passages fluidically
20 coupled to the grooves, a leading edge portion and a trailing edge portion, comprising:

injecting a lubricating fluid into the trailing edge portion;

wherein the lubricating fluid comprises drilling mud.

Preferably, the method further comprises the steps of:

25 positioning the expansion device at least partially within the tubular member;
and

pressurizing a region within the tubular member below the second end of the expansion device.

Preferably, the lubricating fluid has a viscosity ranging from 1 to 10,000
30 centipoise.

Preferably, the injecting includes:

injecting lubricating fluid into the first tapered end of the expansion device.

Preferably, the injecting includes:

injecting lubricating fluid into the area around the axial midpoint of the first tapered end of the expansion device.

5 Preferably, the injecting includes:

injecting lubricating fluid into the second end of the expansion device.

Preferably, the injecting includes:

injecting lubricating fluid into the tapered first end and the second end of the expansion device.

10 Preferably, the injecting includes:

injecting lubricating fluid into the interior of the expansion device.

Preferably, the injecting includes:

injecting lubricating fluid through the outer surface of the expansion device.

Preferably, the injecting includes:

15 injecting the lubricating fluid into a plurality of discrete locations along the trailing edge portion.

Brief Description of the Drawings

20 FIG. 1 is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 2 is a fragmentary cross-sectional view illustrating the placement of an apparatus for creating a casing within the new section of the well borehole.

25

30

HANGING LINERS BY PIPE EXPANSION

5

The field of this invention relates to suspending one tubular in another, especially hanging liners which are to be cemented.

10

In completing wellbores, frequently a liner is inserted into casing and suspended from the casing by a liner hanger. Various designs of liner hangers are known and generally involve a gripping mechanism, such as slips, and a sealing mechanism, such as a packer which can be of a variety of designs.

15 The objective is to suspend the liner during a cementing procedure and set the packer for sealing between the liner and the casing. Liner hanger assemblies are expensive and provide some uncertainty as to their operation down-hole.

Some of the objects of the preferred embodiment are to accomplish the
20 functions of the known liner hangers by alternative means, thus eliminating the traditionally known liner hanger altogether while accomplishing its functional purposes at the same time in a single trip into the well. Another objective of the preferred embodiment is to provide alternate techniques which can be used to suspend one tubular in another while facilitating a cementing operation and still providing a technique for sealing the tubulars together. Various
25 fishing tools are known which can be used to support a liner being inserted

into a larger tubular. One such device is made by Baker Oil Tools and known as a "Tri-State Type B Casing and Tubing Spear," Product No. 126-09. In addition to known spears which can support a tubing string for lowering into a wellbore, techniques have been developed for expansion of tubulars down-
5 hole. Some of the techniques known in the prior art for expansion of tubulars downhole are illustrated in U.S. Patents 4,976,322; 5,083,608; 5,119,661; 5,348,095; 5,366,012; and 5,667,011.

10 The present invention provides a method as defined in the attached claims.

15 A preferred embodiment of the present invention, together with other arrangements given for illustrative purposes only, will now be described, by way of example only, and with reference to the accompanying drawings in which:

Figures 1-4 are a sectional elevation, showing an arrangement to suspend, cement and seal one tubular to another downhole, using pipe expansion techniques.

20 Figures 5-11a are another arrangement creating longitudinal passages for passage of the cementing material prior to sealing the tubulars together.

Figures 12-15 illustrate yet another arrangement incorporating a sliding sleeve valve for facilitating the cementing step.

25 Figures 16-19 illustrate an embodiment in which a grapple technique is used to suspend the tubular inside a bigger tubular, leaving spaces between the grappling members for passage of cement prior to sealing between the tubulars.

Figures 20-26 illustrate an arrangement involving a sequential flaring of the inner tubular from the bottom up.

Figures 28-30 illustrate an arrangement involving fabrication of the tubular to be inserted to its finished dimension, followed by collapsing it for insertion followed by sequential expansion of it for completion of the operation.

Referring to Figure 1, a tubular 10 is supported in casing 12, using known techniques such as a spear made by Baker Oil Tools, as previously described. That spear or other gripping device is attached to a running string 14. Also located on the running string 14 above the spear is a hydraulic or other type of stroking mechanism which will allow relative movement of a swage assembly 16 which moves in tandem with a portion of the running string 14 when the piston/cylinder combination (not shown) is actuated, bringing the swage 16 down toward the upper end 18 of the tubular 10. As shown in Figure 1 during run-in, the tubular 10 easily fits through the casing 12. The tubular 10 also comprises one or more openings 20 to allow the cement to pass through, as will be explained below. Comparing Figure 2 to Figure 1, the tubular 10 has been expanded radially at its upper end 18 so that a segment 22 is in contact with the casing 12. Segment 22 does not include the openings 20; thus, an annular space 24 exists around the outside of the tubular 10 and inside of the casing 12. While in the position shown in Figure 2, cementing can occur. This procedure involves pumping cement through the tubular 10 down to its lower end where it can come up and around

into the annulus 24 through the openings 20 so that the exterior of the tubular 10 can be fully surrounded with cement up to and including a portion of the casing 12. Before the cement sets, the piston/ cylinder mechanism (not shown) is further actuated so that the swage assembly 16 moves further
• 5 downwardly, as shown in Figure 3. Segment 22 has now grown in Figure 3 so that it encompasses the openings 20. In essence, segment 22 which is now against the casing 12 also includes the openings 20, thereby sealing them off. The seal can be accomplished by the mere physical expansion of segment 22 against the casing 12. Alternatively, a ring seal 26 can be placed
10 below the openings 20 so as to seal the cemented annulus 24 away from the openings 20. Optionally, the ring seal 26 can be a rounded ring that circumscribes each of the openings 20. Additionally, a secondary ring seal similar to 26 can be placed around the segment 22 above the openings 20. As shown in Figure 3, the assembly is now fully set against the casing 12. The
15 openings 20 are sealed and the tubular 10 is fully supported in the casing 12 by the extended segment 22. Referring to Figure 4, the swage assembly 16, as well as the piston/cylinder assembly (not shown) and the spear which was used to support the tubular 10, are removed with the running string 14 so that what remains is the tubular 10 fully cemented and supported in the casing 12.
20 The entire operation has been accomplished in a single trip. Further completion operations in the wellbore are now possible.

Figures 5-12 illustrate an alternative arrangement. Here again, the tubular 28 is supported in a like manner as shown in Figures 1-4, except that
25 the swage assembly 30 has a different configuration. The swage assembly

30 has a lower end 32 which is best seen in cross-section in Figure 8. Lower end 32 has a square or rectangular shape which, when forced against the tubular 28, leaves certain passages 34 between itself and the casing 36. Now referring to Figure 7, it can be seen that when the lower end 32 is brought inside the upper end 38 of the tubular 28, the passages 34 allow communication to annulus 40 so that cementing can take place with the pumped cement going back up the annulus 40 through the passages 34. Referring to Figure 8, it can be seen that the tubular 28 has four locations 42 which are in contact with the casing 36. This longitudinal surface location in contact with the casing 36 provides full support for the tubular 28 during the cementing step. Thus, while the locations 42 press against the inside wall of the casing 36 to support the tubular 28, the cementing procedure can be undertaken in a known manner. At the conclusion of the cementing operation, an upper end 44 of the swage assembly 30 is brought down into the upper end 38 of the tubular 28. The profile of the upper end 44 is seen in Figure 10. It has four locations 46 which protrude outwardly. Each of the locations 46 encounters a mid-point 48 (see Figure 8) of the upper end 38 of the tubular 28. Thus, when the upper end 44 of the swage assembly 30 is brought down into the tubular 28, it reconfigures the shape of the upper end 38 of the tubular 28 from the square pattern shown in Figure 8 to the round pattern shown in Figure 12. Figure 11 shows the running assembly and the swage assembly 30 removed, and the well now ready for the balance of the completion operations. The operation has been accomplished in a single trip into the wellbore. Accordingly, the principal difference in the arrangement shown in Figures 1-4 and that shown in Figures 5-12 is that the first arrangement employed holes

Figures 16-19 illustrate an embodiment of the invention. The initial support of the tubular 60 to the casing 62 is accomplished by forcing a grapple member 64 down into an annular space 66 such that its teeth 68 ratchet down over teeth 70, thus forcing teeth 72, which are on the opposite side of the grappling member 64 from teeth 68, to fully engage the inner wall 74 of the casing 62. This position is shown in Figure 17, where the teeth 68 and 70 have engaged, thus supporting the tubular 60 in the casing 62 by forcing the teeth 72 to dig into the inner wall 74 of the casing 62. The grapple members 64 are elongated structures that are placed in a spaced relationship as shown in Figure 17A. The spaces 76 are shown between the grapple members 64. Thus, passages 76 provide the avenue for cement to come up around annulus 78 toward the upper end 80 of the tubular 60. At the conclusion of the cementing, the swage assembly 82 is brought down into the upper end 80 of the tubular 60 to flare it outwardly into sealing contact with the inside wall 74 of the casing 62, as shown in Figure 18. Again, a seal can be used optionally between the upper end 80 and the casing 62 to seal in addition to the forcing of the upper end 80 against the inner wall 74, shown in Figure 18. The running assembly as well as the swage assembly 82 is shown fully removed in Figure 19 and further downhole completion operations can be concluded. All the steps are accomplished in a single trip.

Figures 20-25 illustrate yet another arrangement.

In this situation, the swage assembly 84 has an upper end 86 and a lower end 88. In the run-in position shown in Figure 20, the upper end 86 is located below a flared out portion 90 of the tubular 92. Located above the upper end 86 is a sleeve 94 which is preferably made of a softer material than the tubular

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1. The method of completing a well, comprising:
running in a tubular string into a cased borehole;
5 inserting at least one gripping member between said
tubular string and cased borehole to support said
tubular string;
leaving a gap adjacent said gripping member;
flowing a sealing material through said gap;
10 sealing said gap.
2. The method of claim 1, further comprising:
expanding said tubular string uphole of said
gripping member as said sealing said gap.
15
3. The method of claim 2, further comprising:
providing a plurality of gripping members to
support said tubular string;
wedging said gripping members in a spaced relation
20 to each other to create longitudinal gaps between said
tubular string and said cased borehole for flow of said
sealing material.
4. The method of claim 3, further comprising:
25 wedging said gripping members below a top end of
said tubular string;
expanding said tubular string between said top end
and said gripping members into sealing contact with said
cased borehole.
30
5. The method of claim 4, further comprising:
accomplishing said running in, inserting the
gripping member, leaving a gap, flowing the sealing
material, and sealing said gap in a single trip in the
35 well.

and into the casing from which it is suspended, including cement, blast furnace slag, or other materials. Known techniques are used for operating the sliding sleeve valve shown in Figure 12-15, which selectively exposes the openings 50. Other types of known valve assemblies are also contemplated. Despite the variations, the technique winds up being a one-trip operation.

5

Those skilled in the art will now appreciate that what has been disclosed is a method which can completely replace known liner hangers and allows for sealing and suspension of tubulars in larger tubulars, with the flexibility of cementing or otherwise encasing the inserted tubular into the larger tubular.

10

The foregoing disclosure and description of the invention are illustrative and explanatory thereof, and various changes in the size, shape and materials, as well as in the details of the illustrated construction, may be made.

92, such as aluminum, for example. The outside diameter of the flared out segment 90 is still less than the inside diameter 96 of the casing 98. Ultimately, the flared out portion 90 is to be expanded, as shown in Figure 21, into contact with the inside wall of the casing 98. Since that distance representing that expansion cannot physically be accomplished by the upper end 96 because of its placement below the flared out portion 90, the sleeve 94 is employed to transfer the radially expanding force to make initial contact with the inner wall of casing 98. The upper end 86 of the swage assembly 84 has the shape shown in Figure 22 so that several sections 100 of the tubular 92 will be forced against the casing 98, leaving longitudinal gaps 102 for passage of cement. In the position shown in Figures 21 and 22, the passages 102 are in position and the sections 100 which have been forced against the casing 98 fully support the tubular 92. At the conclusion of the cementing operation, the lower segment 88 comes into contact with sleeve 94. The shape of lower end 88 is such so as to fully round out the flared out portion 90 by engaging mid-points 104 of the flared out portion 90 (see Figure 22) such that the passages 102 are eliminated as the sleeve 94 and the flared out portion 90 are in tandem pressed in a manner to fully round them, leaving the flared out portion 90 rigidly against the inside wall of the casing 98. This is shown in Figure 23. Figure 25 illustrates the removal of the swage assembly 84 and the tubular 92 fully engaged and cemented to the casing 98 so that further completion operations can take place. Figures 24 and 26 fully illustrate the flared out portion 90 pushed hard against the casing 98. Again, in this arrangement as in all the others, auxiliary sealing devices can be used be-

tween the tubular 92 and the casing 98 and the process is done in a single trip.

Referring now to Figures 27-30, yet another arrangement is illustrated. Again, the similarities in the running in procedure will not be repeated because they are identical to the previously described arrangements. In this situation, the tubular 106 is initially formed with a flared out section 108. The diameter of the outer surface 110 is initially produced to be the finished diameter desired for support of the tubular 106 in a casing 112 (see Figure 28) in which it is to be inserted. However, prior to the insertion into the casing 112 and as shown in Figure 28, the flared out section 108 is corrugated to reduce its outside diameter so that it can run through the inside diameter of the casing 112. The manner of corrugation or other diameter-reducing technique can be any one of a variety of different ways so long as the overall profile is such that it will pass through the casing 112. Using a swage assembly of the type previously described, which is in a shape conforming to the corrugations illustrated in Figure 28 but tapered to a somewhat larger dimension, the shape shown in Figure 29 is attained. The shape in Figure 29 is similar to that in Figure 28 except that the overall dimensions have been increased to the point that there are locations 114 in contact with the casing 112. These longitudinal contacts in several locations, as shown in Figure 29, fully support the tubular 106 in the casing 112 and leave passages 116 for the flow of cement. The swage assembly can be akin to that used in Figures 5-11 in the sense that the corrugated shape now in contact with the casing 112 shown in Figures 29 at locations 114 can be made into a round shape at the conclusion of the cementing operation. Thus, a second portion of the swage assembly as

previously described is used to contact the flared out portion 108 in the areas where it is still bent, defining passages 116, to push those radially outwardly until a perfect full 360° contact is achieved between the flared out section 108 and the casing 112, as shown in Figure 30. This is all done in a single trip.

5 Those skilled in the art can readily appreciate that various arrangements have been disclosed which allow a tubular, such as 10, to be suspended in a running assembly. The running assembly is of a known design and has the capability not only of supporting the tubular for run-in but also to actuate a swage assembly of the type shown, for example, in Figure 1 as item 16. What
10 is common to all these techniques is that the tubular is first made to be supported by the casing due to a physical expansion technique. The cementing takes place next and the cementing passages are then closed off. Since it is important to allow passages for the flow of cement, the apparatus of the present invention provides a technique which
15 allows this to happen with the tubular supported while subsequently closing them off. The technique can work with a swage assembly which is moved downwardly into the top end of the tubular or in another arrangement, such as shown in Figures 20-26, the swage assembly is moved upwardly, out of the top end of the tubular. The creation of passages for the cement, such as 34
20 in Figure 8, 76 in Figure 17A, or 102 in Figure 22, can be accomplished in a variety of ways. The nature of the initial contact used to support the tubular in the casing can vary. Thus, although four locations are illustrated for the initial support contact in Figure 8, a different number of such locations can be used. Different materials can be used to encase the liner up

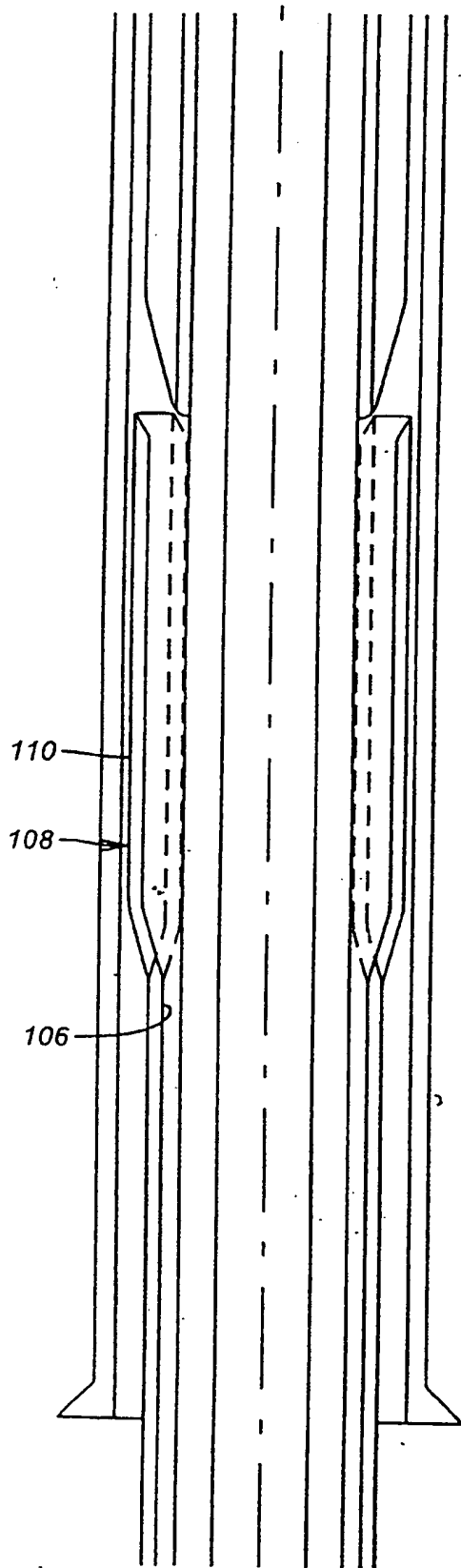


FIG. 27

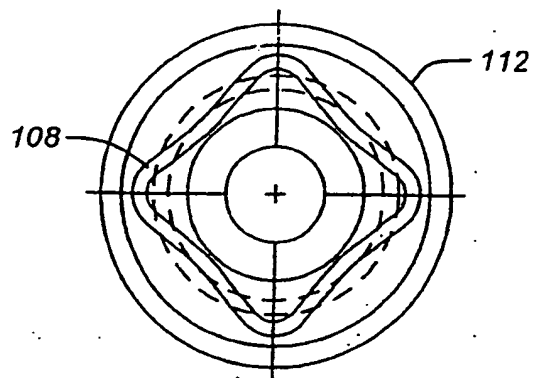


FIG. 28

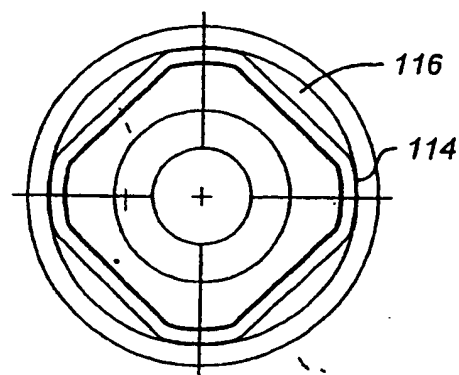


FIG. 29

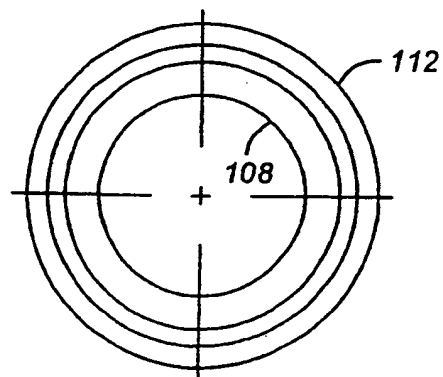


FIG. 30

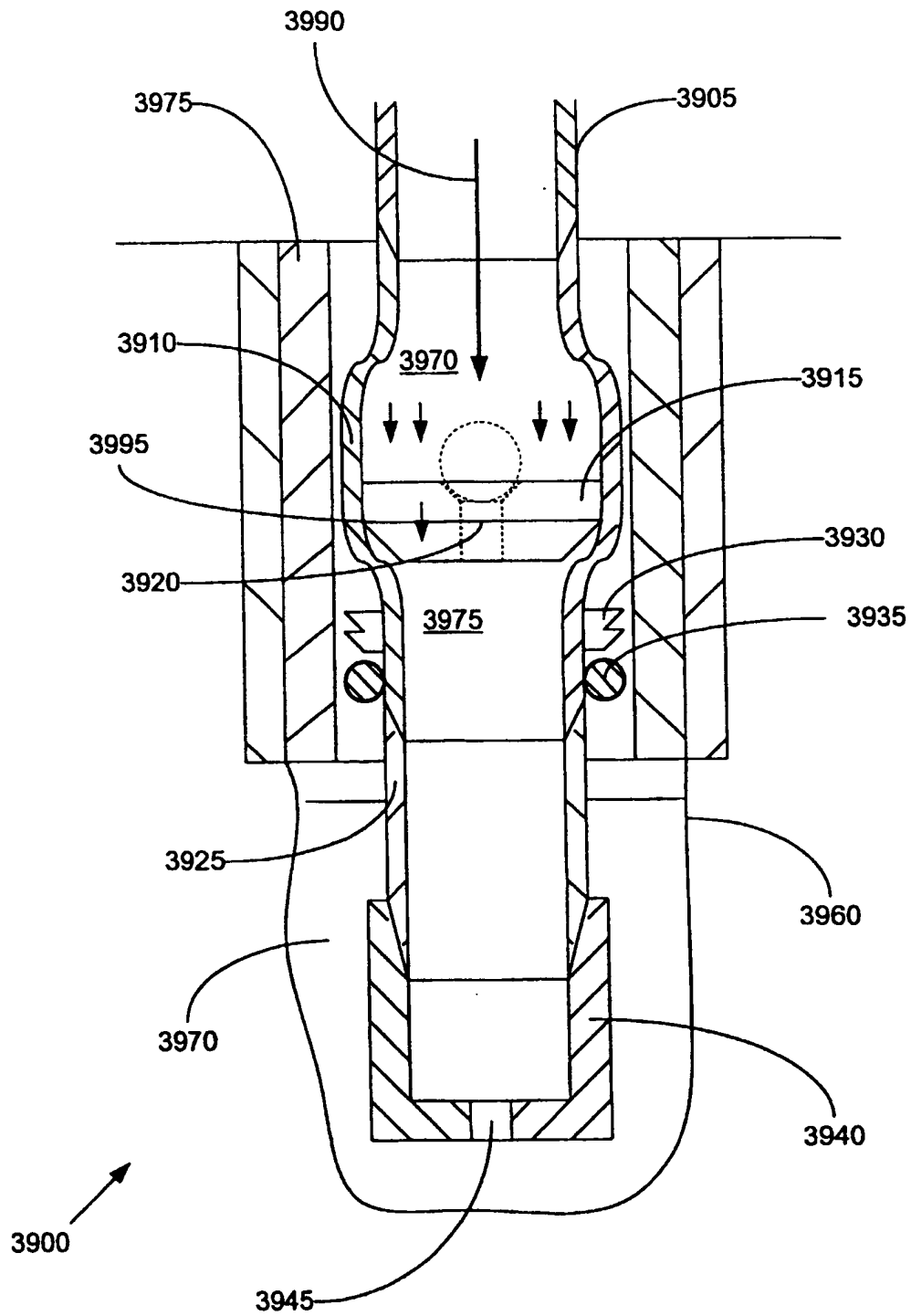


FIGURE 24D

with that completion.

While the method and apparatus known to the prior art as set forth above is favored by many and has performed well for its intended purpose, it does unfortunately have a drawback in that solids such as sand, gravel, etc. can make their way into the main wellbore by sliding around the annulus existing between the open hole and the slotted sleeve. While the well can still be produced with such solids, it is well known to the art that sand and other solids have detrimental effects on wellbore equipment and pumping equipment and indeed if a pump is dropped below the lateral window that is the source of sand ingress it would be directly exposed to such solids and likely would have a very limited life expectancy.

SUMMARY OF THE INVENTION

The above-identified drawbacks of the prior art are overcome, or alleviated, by the method and apparatus of the invention.

The invention employs an expandable sleeve device which for purposes of this application means a sleeve having a plurality of openings through an outer surface thereof to promote expansion of the device due to pressure exerted thereagainst from an inside surface thereof. A preferred embodiment employs slots which are offset to one another such that the device is expandable by deformation of the slots. The device includes a hook protruding from one side thereof and a premachined window uphole of and centered with respect to the hook. The premachined window provides main borehole access when the expandable sleeve device is in place while the hook ensures that the premachined window is aligned with the main borehole by engaging with the milled window in the primary borehole casing. The expandable sleeve junction further includes an outer material which is also expandable and which will prevent ingress of fluids and solids through the slots in the expandable sleeve junction. Once deformed, the expandable sleeve junction provides enhanced (over the prior art) structural support to an unconsolidated well formation in an open hole and further prevents particulate matter from entering the main bore by washing around the annulus of the expandable sleeve. This is accomplished since the annulus has been reduced sufficiently by expansion of the expandable sleeve junction to where sand and

other particulate matter will bridge naturally and be excluded from ingress to the main wellbore.

In general terms, the expandable sleeve junction is mounted to the uphole end of a standard liner and on a running tool to be delivered to the desired junction. The expandable sleeve junction engages with a milled window through which the liner has passed. The sleeve both hangs and is oriented to the primary borehole via the hook. Following run-in, a packer or other expandable element is expanded inside the expandable sleeve junction thereby expanding its outside dimensions. The expandable sleeve is preferably expanded at least nearly into contact with the open hole bore of the lateral borehole. Subsequent to this deformation, the packer or other element is deactuated and the running tool withdrawn from the wellbore.

The invention ensures that significant particulate matter will not enter the main borehole and therefore not damage downhole equipment. Another and important benefit of the invention over prior art systems is that it allows for complete installation without requiring additional runs of tools in the wellbore. Thus, no additional expense is required with respect to setting the slotted sleeve junction beyond what would be required to set a liner in the lateral borehole. It will of course, be understood that more runs could be added if desired.

IN THE DRAWINGS

Referring now to the drawings wherein like elements are numbered alike in the several FIGURES:

FIGURE 1 is a schematic cross-section of the slotted sleeve junction of the invention illustrating both the elastomeric outer covering and the slotted sleeve as well as the premachined window and hook;

FIGURE 2 schematically illustrates a protective sleeve employed to prevent the packer from extruding through the premachined window in the slotted sleeve junction.

FIGURE 3 is a schematic view of a primary and lateral wellbore illustrated with a whipstock mounted in the primary wellbore;

FIGURE 4 is a schematic illustration of the same wellbore after the packer has

been removed and the downhole end of a liner with a bent sub is being introduced to the lateral borehole;

FIGURE 5 is a schematic illustration of the invention being placed at the junction between the primary borehole and the lateral borehole;

5 FIGURE 6 is another schematic illustration showing the packer expanding within the slotted sleeve junction to expand the same;

FIGURE 7 illustrates the next step in the process of the invention with the expandable element unexpanded and be in a condition where the running tool will be removed from the wellbore; and

10 FIGURE 8 is a schematic illustration of the completed wellbore with the slotted sleeve junction and the liner permanently installed.

DETAILED DESCRIPTION OF THE INVENTION

The invention as noted solves preexisting problems of sand or other small
15 particulate ingress to the primary borehole at a junction thereof with a lateral borehole.

Also, and as stated, this is accomplished through a particular method of the invention which is preferably made possible by employment of an apparatus of the invention. Initially, therefore, reference is made to Figures 1 and 2 to introduce the apparatus of the invention after which the preferred method of its use is discussed.

20 Referring to Figure 1, a cross section view of an expandable sleeve junction 10 which may comprise solid material or in one preferred embodiment and as illustrated may comprise a slotted sleeve. In the following description, the slotted embodiment is detailed. It will be understood, however, that solid materials being swaged to expand them, etc. are contemplated herein. The construction of junction 10 preferably
25 includes a slotted sleeve 12 constructed of a metal such as steel which still exhibits, strength after deforming. Sleeve 12 includes slots 14 (as shown in the drawings however other shapes can be substituted as noted above with the goal of allowing the sleeve to expand) in an offset pattern facilitative of an expansion of the outside diameter of the junction 10 by opening of slots 14. The particular dimensions of
30 undeformed slots 14 will depend upon the degree of expansion of junction 10 desired. Determining the dimensions of the slots needed to allow the desired expansion is

within the level of skill of one of ordinary skill in the art.

Attached to sleeve 12 is hook 16 to support a lateral liner in the lateral borehole. The hook 16 operates as does a prior art hook liner hanger system such as product no.29271, commercially available from Baker Oil Tools, Houston, Texas. In connection with the invention, hook 16 is employed also to orient a primary borehole access window 18 with a primary borehole from which the subject lateral extends. Window 18 provides full bore access to the primary borehole subsequent to the method of the invention being completed.

Since expansion the slotted sleeve 12 will necessarily cause relatively large dimension openings to exist throughout sleeve 12, it is desirable and preferable to provide a material on an outside surface of sleeve 12 as illustrated at 20. Material 20 can be constructed of any material that has expandable characteristics and is capable of withstanding the environment downhole. Rubber or plastic material is preferred although it is possible that a metallic material could be employed if it possesses the desired expansion characteristics. Material 20 functions to seal all of the openings of slots 14 to screen out substantially any particulate matter from entering the primary borehole.

Referring now to Figure 2, a shield 22 is illustrated. Shield 22 is constructed to nest with window 18 of sleeve 12 to prevent extrusion of a packer through that window upon expansion thereof to expand the junction 10 in accordance with the method of the invention. The shield 22 preferably includes boundary area 24 which overlaps with edges of window 18. Shield 22 is thus put into place in the window from the inside of junction 10 and thereby cannot be pushed through window 18 to the outside of junction 10.

Figure 2 also provides a schematic illustration of position of the components of the invention by illustrating a conventional running tool 26. The operation of the tool of the invention and other components thereof will be further understood through reference to Figures 3-8 which provide a schematic sequential view of the tool in action.

One of ordinary skill in the art will recognize the illustration of Figure 3 as a primary borehole 30 and a lateral borehole 32. One will also recognize the schematic

depiction of a whipstock 34 placed in primary borehole 30 immediately downhole of an intersection with lateral borehole 32. Referring now to Figure 4, the whipstock 34 has been removed from the primary borehole 30 and a liner 36 is being run in the hole. Preferably liner 36 includes a bent sub 38 at the downhole end to allow the assembly
5 to easily enter the lateral borehole 32. In Figure 5, liner 36 is at its final depth and the slotted sleeve junction 10 of the invention is illustrated in place with the hook 16 engaged with window 40 of primary borehole. As is known, hook 16 supports the weight of liner 36 but additionally in the invention, acts to orient window 18 with primary borehole 30. It is important to note that an expandable element is also
10 positioned on running tool 26. Expandable element 42 may be an inflatable packer, squeeze packer or other device capable of increasing the dimensions of slotted sleeve junction 10 through deformation.

Referring to Figure 6, the element 42 is illustrated in an expanded condition which urges junction 10 against borehole 32. Shield 22 is shown preventing the
15 expansion of element 42 through window 18. Upon completion of the expansion phase the junction is permanently deformed to exhibit a larger outside dimension than it possessed at run-in whereby structural support is provided to the borehole 32 near its root. Subsequently, and with reference to Figure 7, the expandable element 42 is unexpanded and can be withdrawn from the wellbore. This leaves junction 10 in
20 place against the walls of borehole 32 with a small enough gap between the borehole and the junction 10 to facilitate natural sand bridging and therefore exclude such sand from the primary borehole 30. It will also be noted that as element 42 and running tool 26 are withdrawn from the wellbore, shield 22 is likewise withdrawn although it is not illustrated in Figure 7. Figure 8 illustrates, schematically, the completed
25 wellbore.

The device of the invention and its method of installation significantly improve the prior art since in the same run into the well as is done in the prior art, the invention eliminates the drawbacks of the prior art as discussed hereinabove.

While preferred embodiments have been shown and described, various
30 modifications and substitutions may be made thereto without departing from the spirit and scope of the invention. Accordingly, it is to be understood that the present

invention has been described by way of illustration and not limitation.

CLAIMS

CLAIM 1. A junction comprising:

an expandable sleeve junction;

a premachined window in said expandable sleeve; and

a hook extending from said expandable sleeve and engageable with a window

5 in a primary borehole.

CLAIM 2. A junction as claimed in claim 1 wherein said expandable sleeve includes a plurality of slots.

CLAIM 3. A junction as claimed in claim 2 wherein said slots are arranged in an offset pattern.

CLAIM 4. A junction tool comprising:

an expandable sleeve junction;

a premachined window in said expandable sleeve;

a hook extending from said expandable sleeve and engageable with a window

5 in a primary borehole;

a liner extending from said expandable sleeve;

a shield positioned in said premachined window in said expandable sleeve;

and

an expandable element disposed within said expandable sleeve.

CLAIM 5. A junction tool as claimed in claim 4 wherein said expandable sleeve is slotted.

CLAIM 6. A junction tool as claimed in claim 4 wherein said slotted sleeve junction further includes a material disposed at an outside surface thereof.

CLAIM 7. A junction tool as claimed in claim 6 wherein said material is expandable without rupturing.

CLAIM 8. A junction tool as claimed in claim 6 wherein said material is elastomeric.

CLAIM 9. A junction tool as claimed in claim 6 wherein said material is metallic.

CLAIM 10. A junction tool as claimed in claim 5 wherein said slots are offset.

CLAIM 11. A method for forming a junction between a primary borehole and a lateral borehole in a wellbore comprising:

- running a liner and expandable sleeve junction to depth;
- expanding an expandable element disposed within said expandable sleeve
- 5 junction to deform said expandable sleeve junction into close proximity with an annular wall of said lateral borehole; and
- collapsing said expandable element to be withdrawn from the wellbore.

CLAIM 12. A method for forming a junction as claimed in claim 11 wherein said expandable sleeve is slotted.

CLAIM 13. A method for forming a junction as claimed in claim 11 wherein said expandable element is expanded by dropping a ball and pressuring up on a tubing string connecting said element to an uphole location.

CLAIM 14. A method for forming a junction as claimed in claim 11 wherein said method includes causing said expandable sleeve junction to interact with said lateral borehole so that particulate matter bridges naturally and is excluded from said primary borehole.

CLAIM 15. A method for forming a junction between a primary borehole and a lateral borehole in a wellbore in a single run into the wellbore comprising:

running a liner, an expandable sleeve junction and an expandable element into the wellbore in a single run;

5 expanding said expandable element to expand said sleeve junction into close proximity with an annular wall of said lateral borehole; and

removing said expandable element from said expandable sleeve junction.

CLAIM 16. A method for forming a junction as claimed in claim 15 wherein said expandable sleeve is slotted.



Application No: GB 0029943.8
Claims searched: 1-10

Examiner: Joseph Mitchell
Date of search: 5 March 2001

Patents Act 1977
Search Report under Section 17

Databases searched:

UK Patent Office collections, including GB, EP, WO & US patent specifications, in:

UK CI (Ed.S): EIF (FAB)

Int CI (Ed.7): E21B

Other: EPODOC, WPI, JAPIO

Documents considered to be relevant:

Category	Identity of document and relevant passage	Relevant to claims
Y	GB 2295840 A BAKER HUGHES INC. (Pg 6 lines 2-15, pg 9 line 10-pg 11 line 8)	1-3
Y	EP 0859123 A2 HALLIBURTON ENERGY SERVICES (Col 18 line 44-col 20 line 10)	1-3
Y	WO 99/02818 A1 PETROLINE WELLSYSTEMS LIMITED (Pg 1 line 20-pg 3 line 3)	1-3

X	Document indicating lack of novelty or inventive step	A	Document indicating technological background and/or state of the art.
Y	Document indicating lack of inventive step if combined with one or more other documents of same category.	P	Document published on or after the declared priority date but before the filing date of this invention.
&	Member of the same patent family	E	Patent document published on or after, but with priority date earlier than, the filing date of this application.

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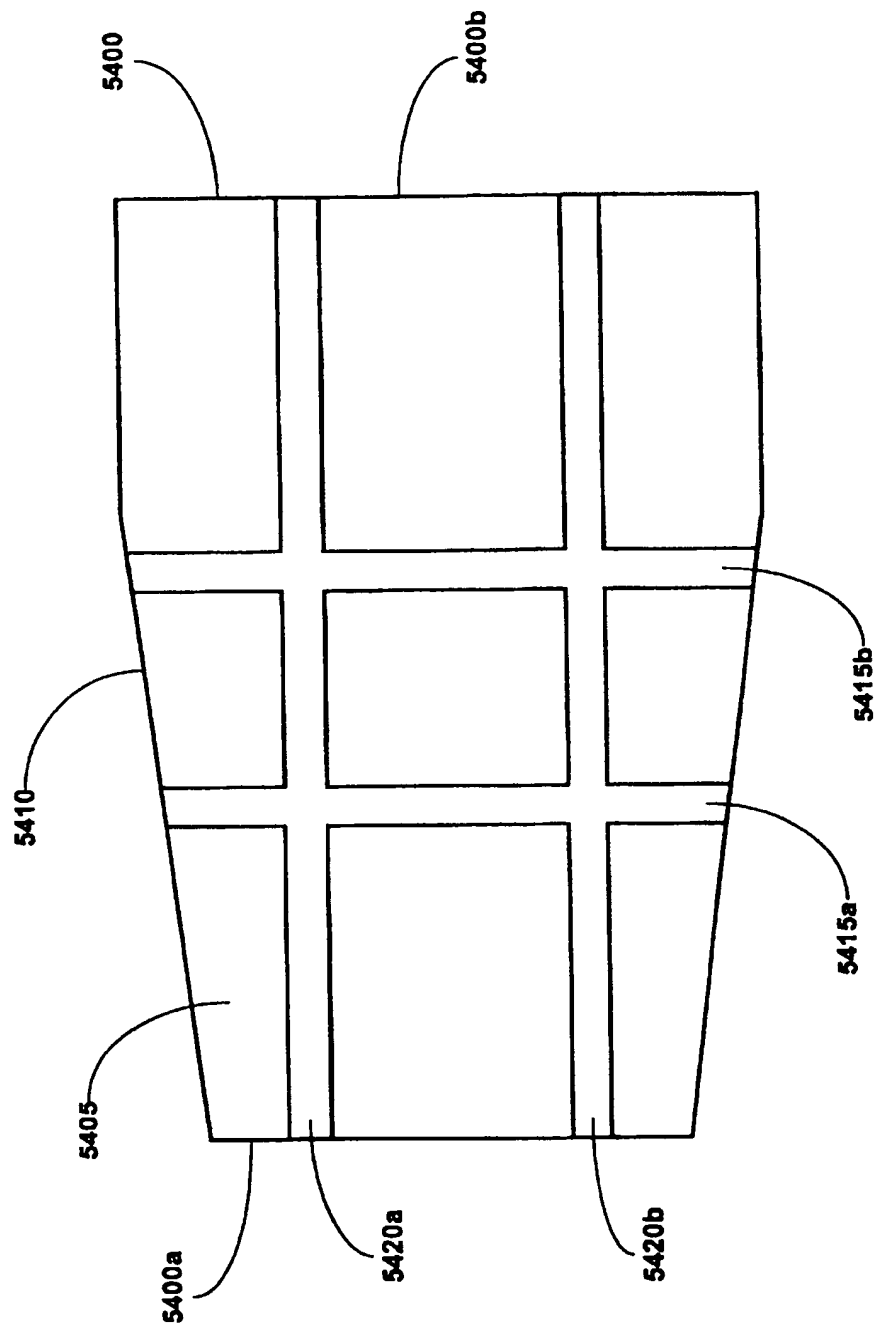


FIGURE 35

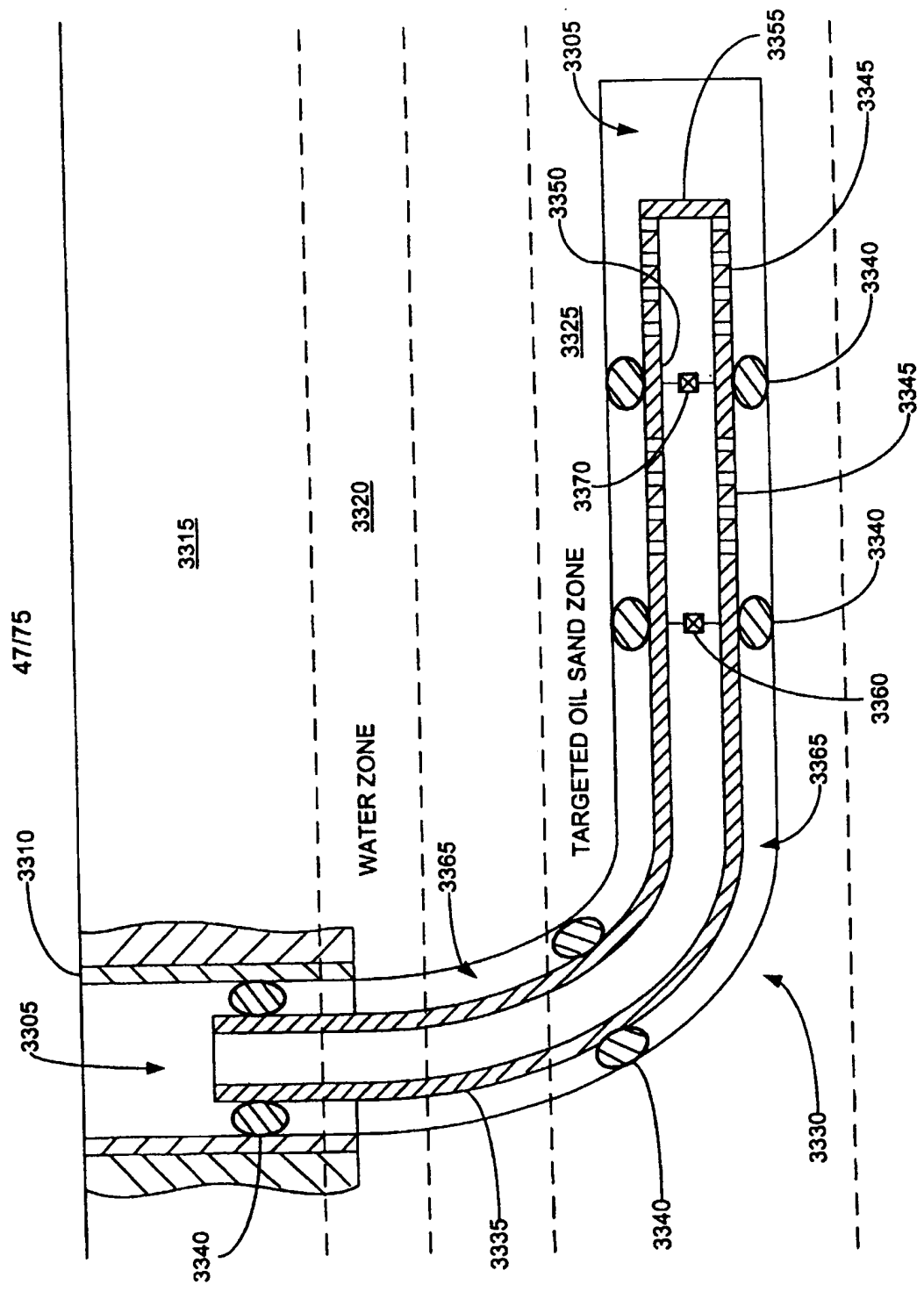


FIGURE 21



FIGURE 22A



FIGURE 22B

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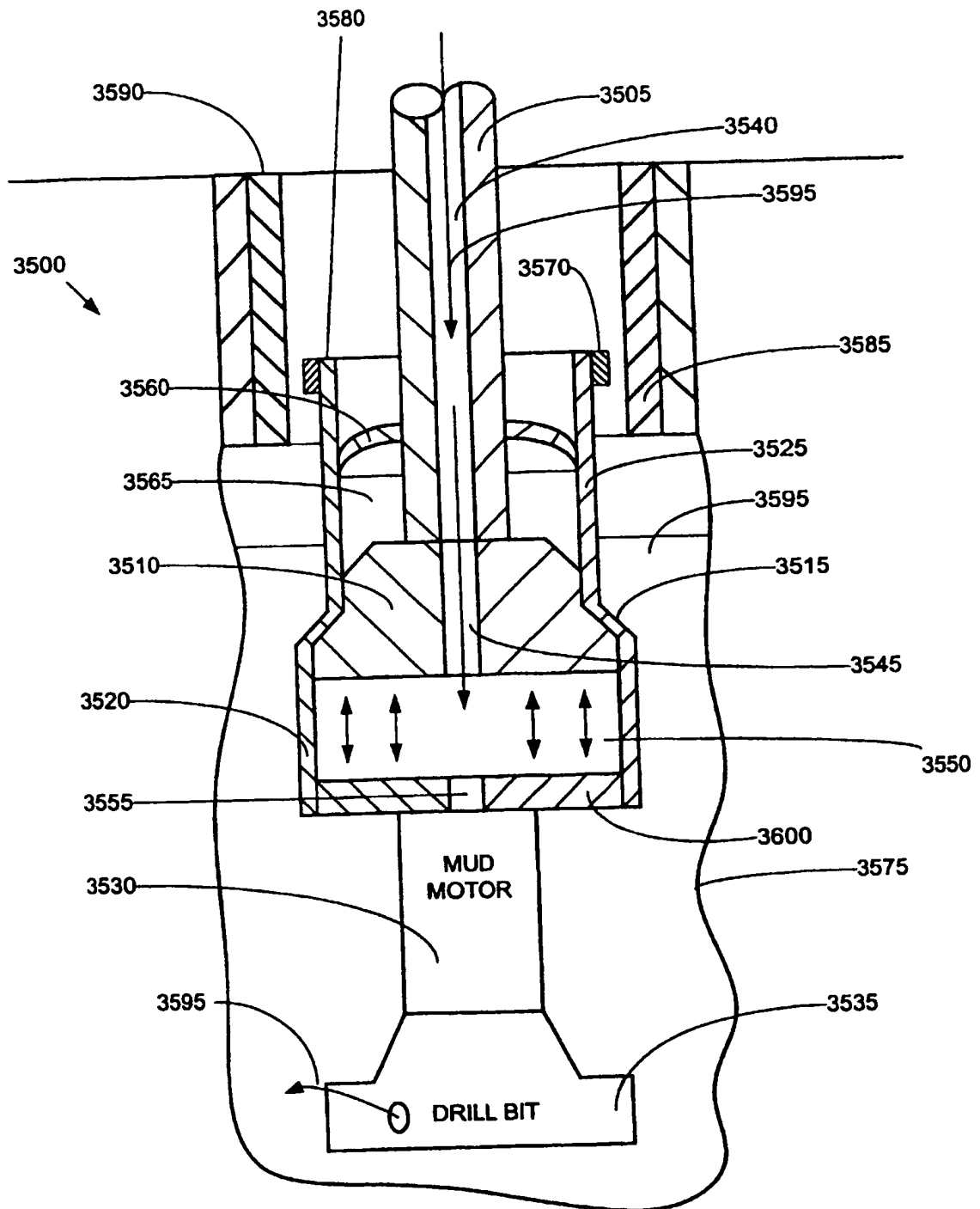
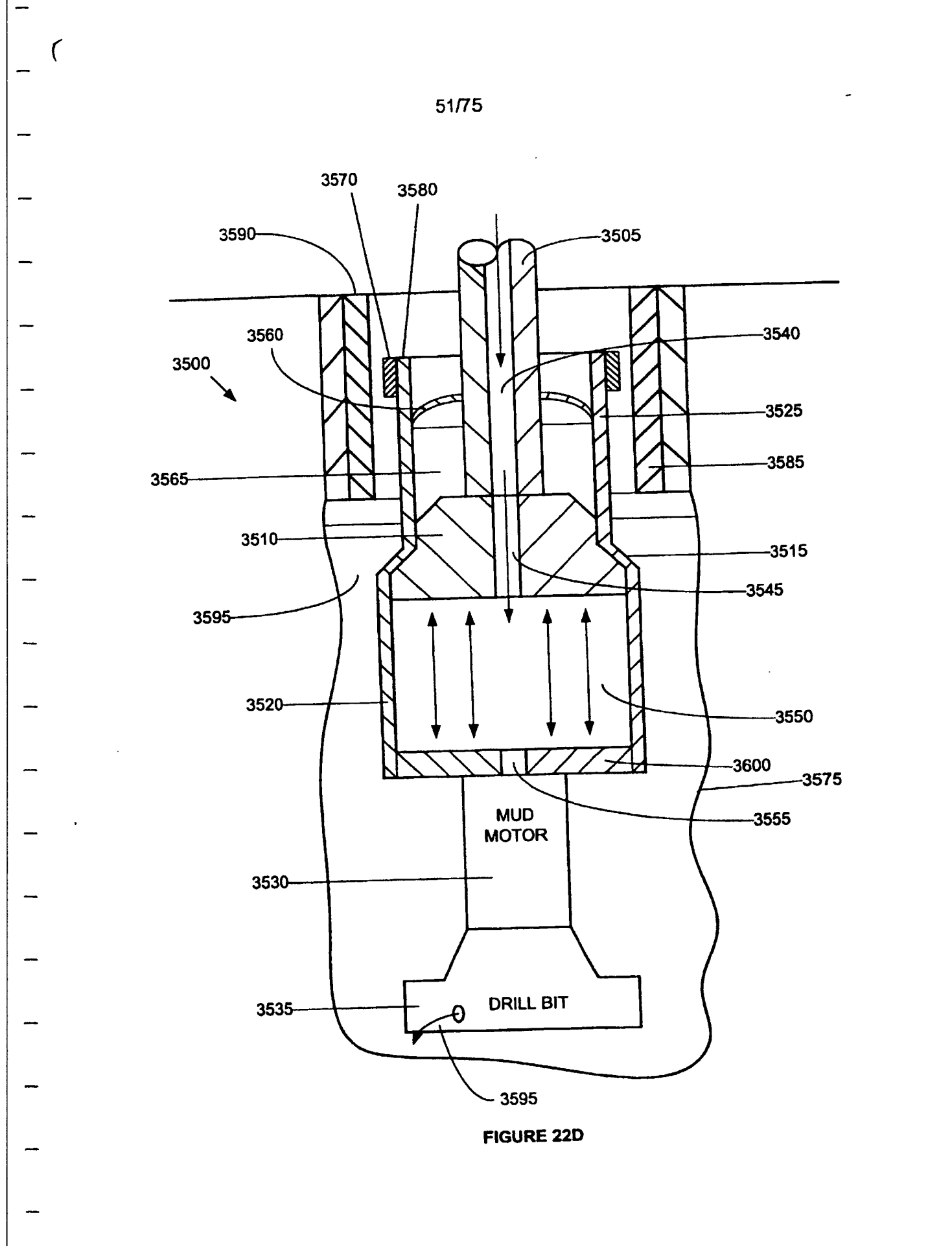


FIGURE 22C



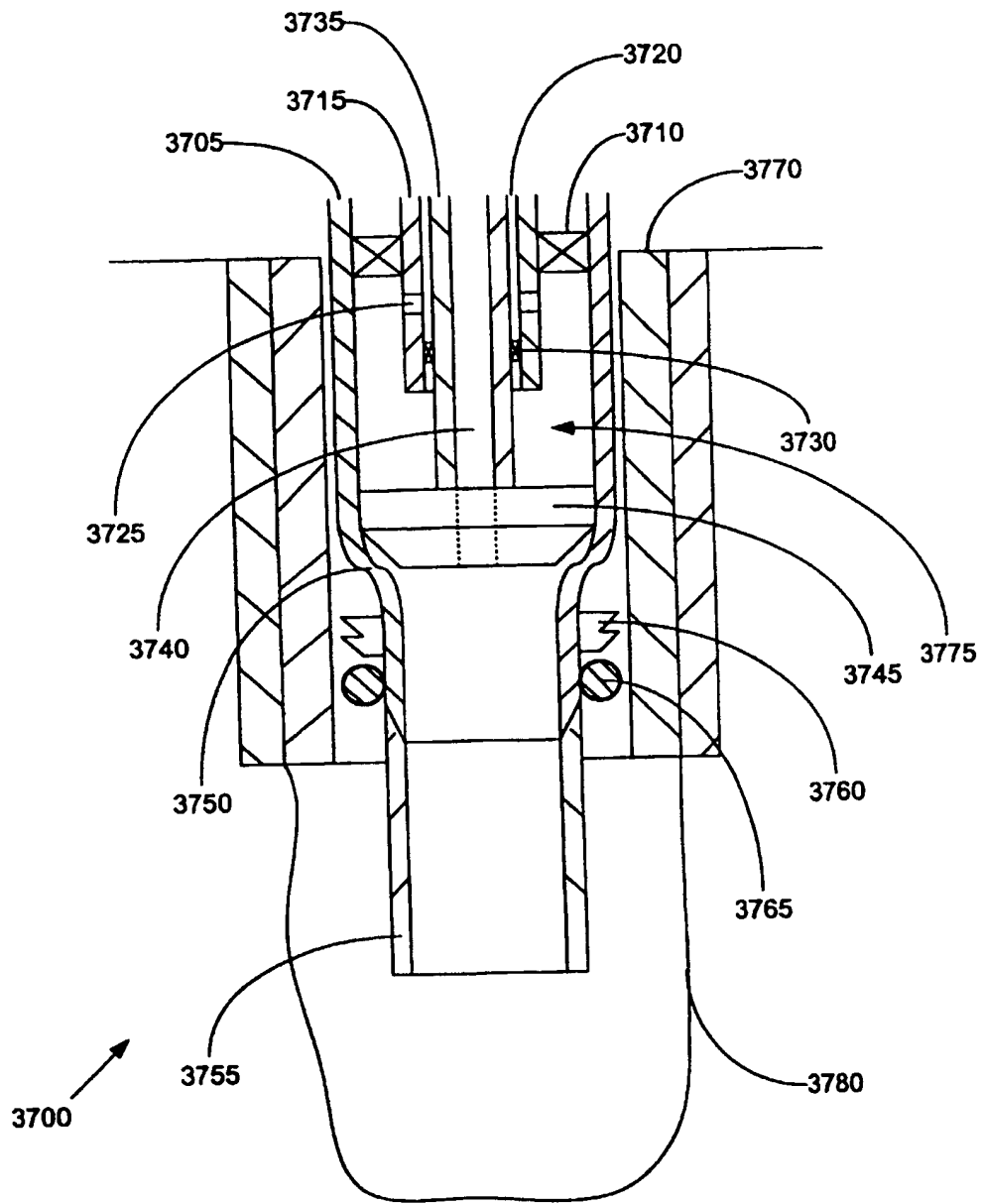


FIGURE 23A

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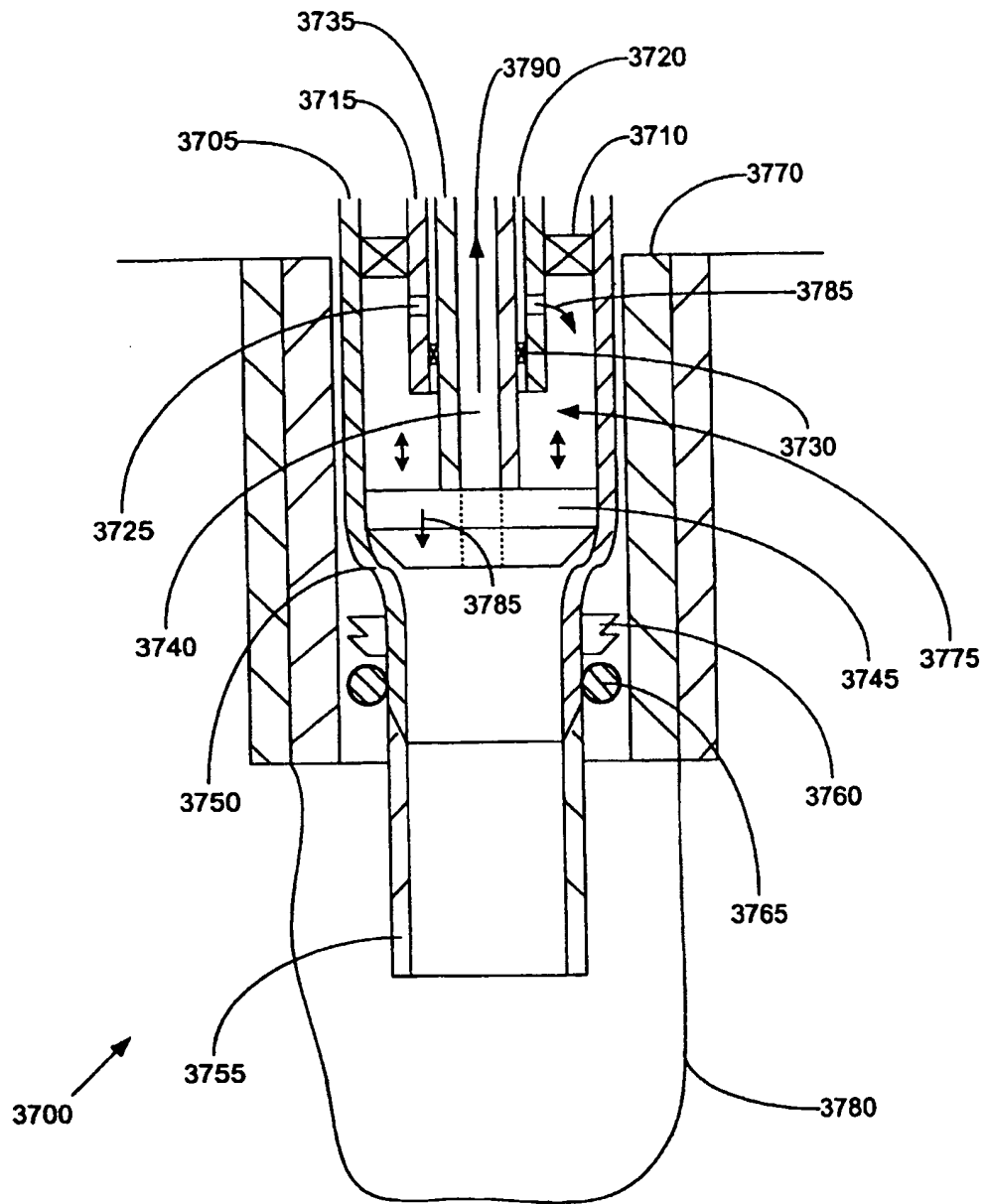


FIGURE 23B

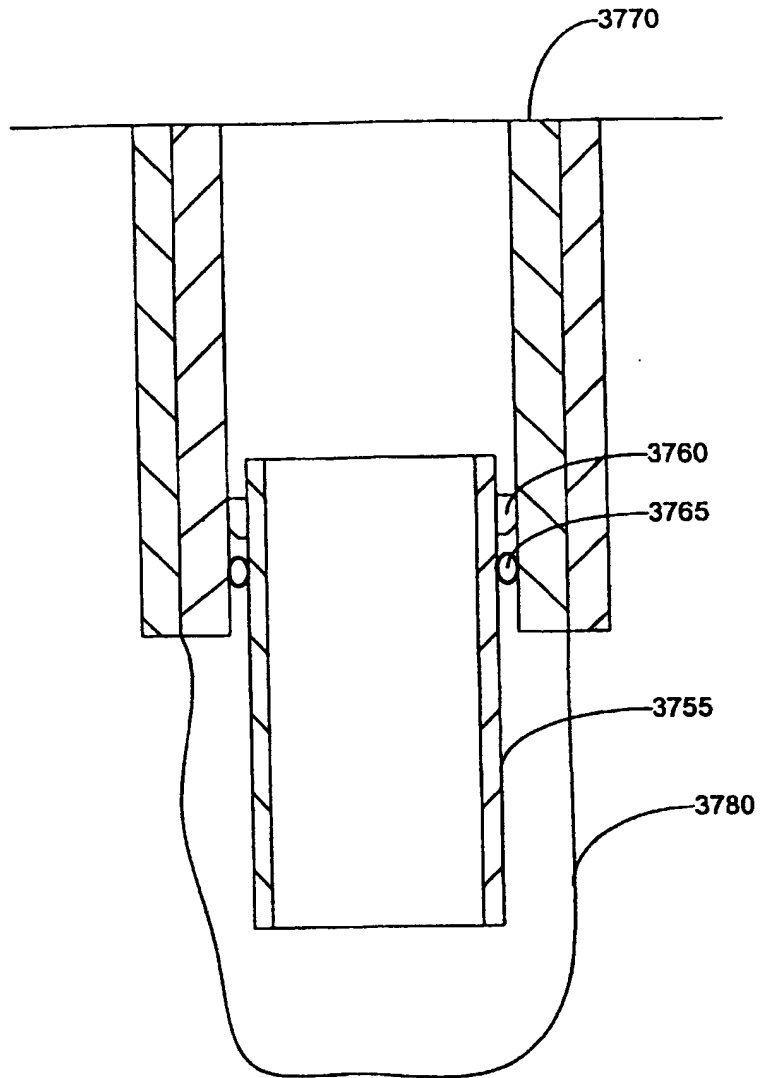


FIGURE 23C

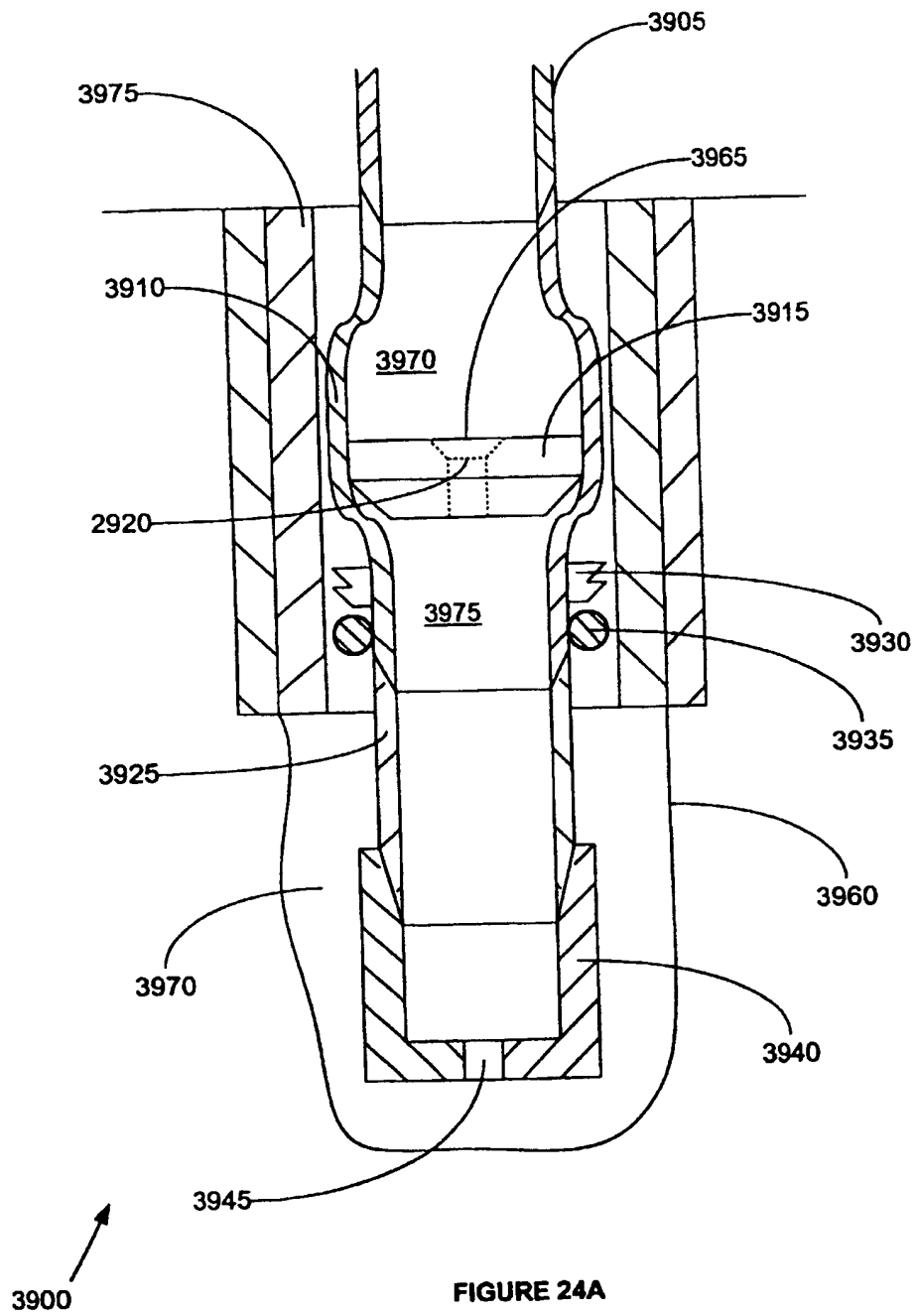


FIGURE 24A

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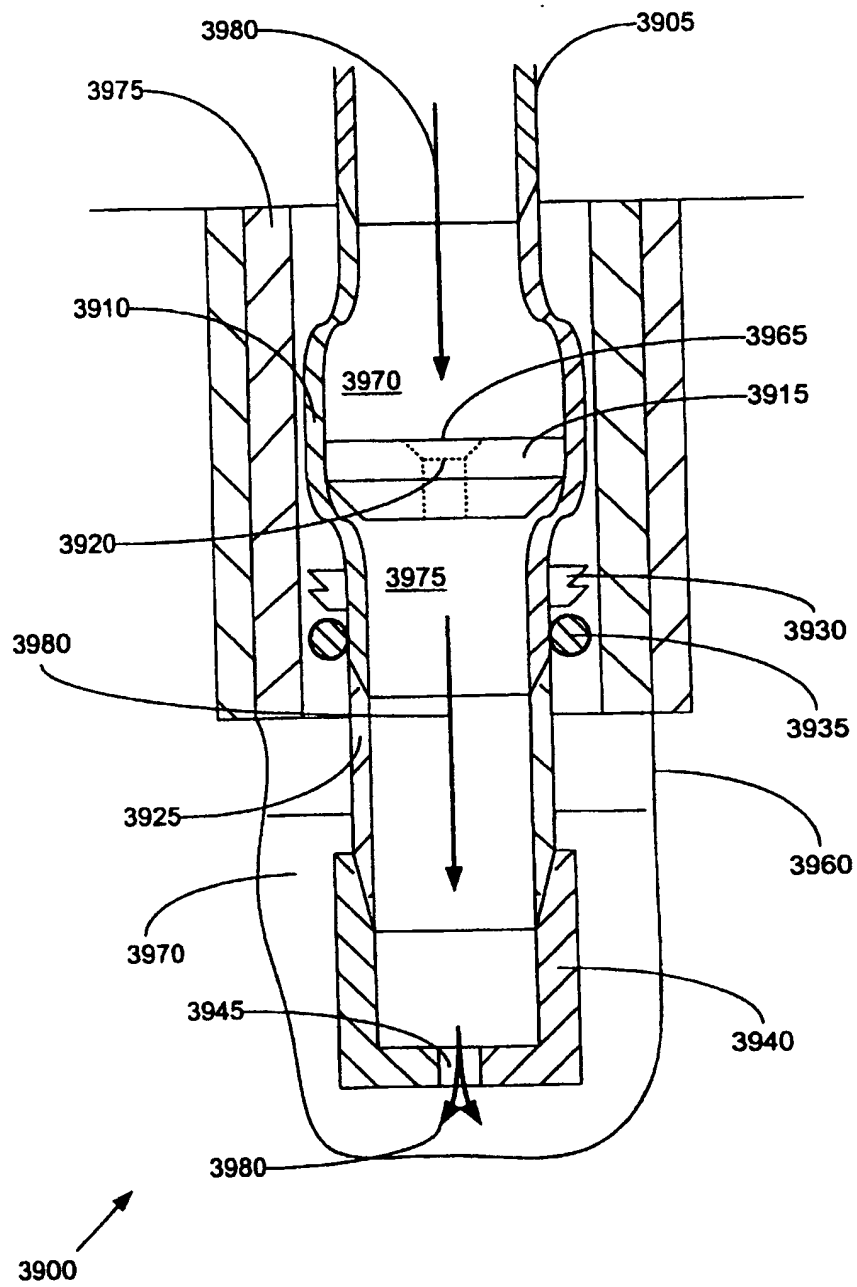


FIGURE 24B

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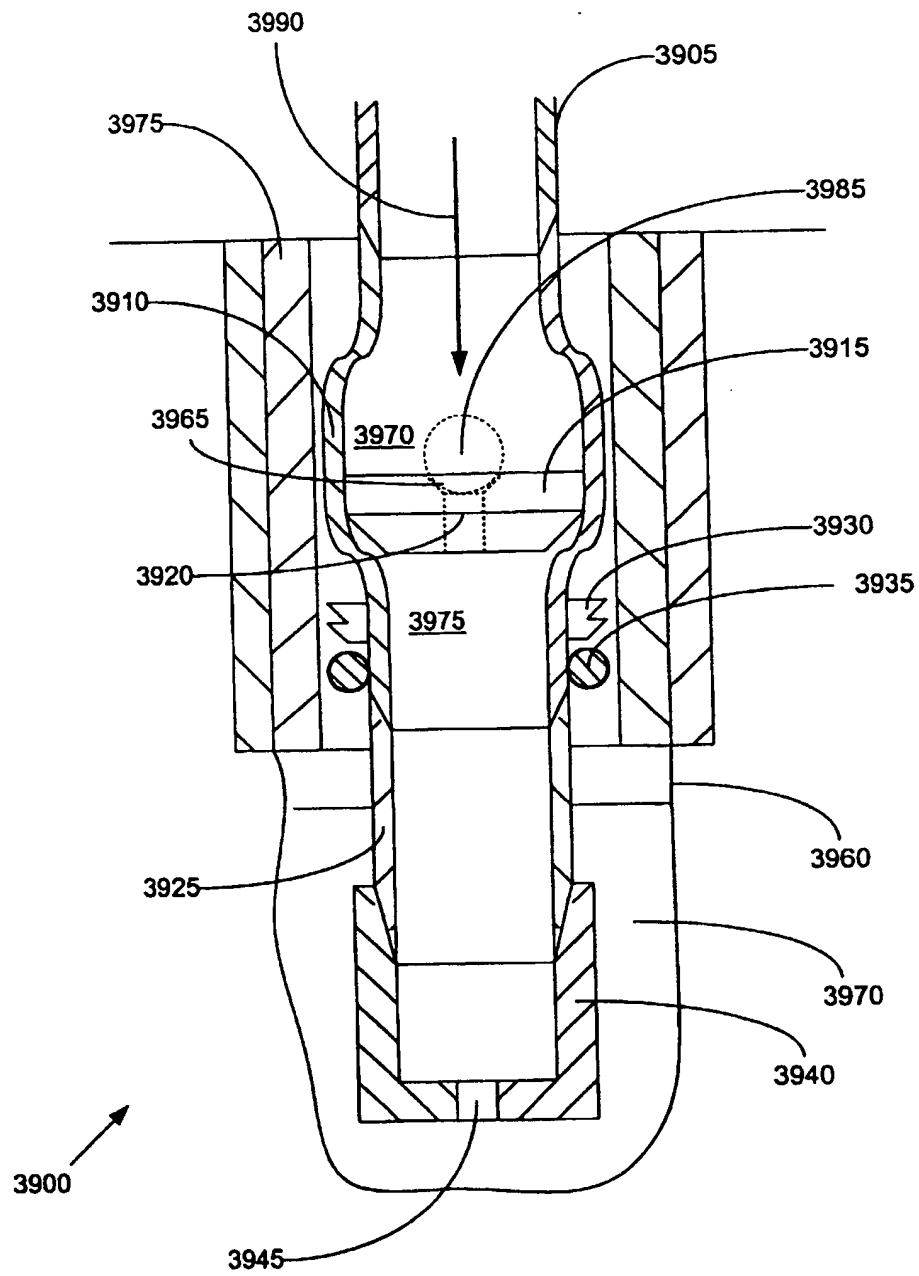


FIGURE 24C

LUBRICATION AND SELF-CLEANING SYSTEM FOR EXPANSION MANDREL

Cross Reference To Related Applications

This application claims the benefit of the filing date of U.S. provisional patent application serial no. 60/137,998, attorney docket no. 25791.17, filed on June 7, 1999, the disclosure of which is incorporated herein by reference.

5 This application is related to the following co-pending applications: provisional patent application number 60/108,558, filed 11/16/1998, provisional patent application number 60/111,293, filed 12/7/1998, provisional patent application number 60/119,611, filed 2/11/1999, provisional patent application number 60/121,702, filed 2/25/1999, provisional patent application number 60/121,907, filed 2/26/1999,
10 provisional patent application number 60/124,042, filed 3/11/1999, and provisional patent application number 60/131,106, filed 4/26/1999, the disclosures of which are incorporated by reference.

Background of the Invention

15 This invention relates generally to wellbore casings, and in particular to wellbore casings that are formed using expandable tubing.

Conventionally, when a wellbore is created, a number of casings are installed in the borehole to prevent collapse of the borehole wall and to prevent undesired outflow of drilling fluid into the formation or inflow of fluid from the formation into the borehole. The borehole is drilled in intervals whereby a casing which is to be
20 installed in a lower borehole interval is lowered through a previously installed casing of an upper borehole interval. As a consequence of this procedure the casing of the lower interval is of smaller diameter than the casing of the upper interval. Thus, the casings are in a nested arrangement with casing diameters decreasing in downward direction. Cement annuli are provided between the outer surfaces of the casings and
25 the borehole wall to seal the casings from the borehole wall. As a consequence of this nested arrangement a relatively large borehole diameter is required at the upper part of the wellbore. Such a large borehole diameter involves increased costs due to heavy casing handling equipment, large drill bits and increased volumes of drilling fluid and

drill cuttings. Moreover, increased drilling rig time is involved due to required cement pumping, cement hardening, required equipment changes due to large variations in hole diameters drilled in the course of the well, and the large volume of cuttings drilled and removed.

5 Conventionally, at the surface end of the wellbore, a wellhead is formed that typically includes a surface casing, a number of production and/or drilling spools, valving, and a Christmas tree. Typically the wellhead further includes a concentric arrangement of casings including a production casing and one or more intermediate casings. The casings are typically supported using load bearing slips positioned above
10 the ground. The conventional design and construction of wellheads is expensive and complex.

Conventionally, a wellbore casing cannot be formed during the drilling of a wellbore. Typically, the wellbore is drilled and then a wellbore casing is formed in the newly drilled section of the wellbore. This delays the completion of a well.

15 The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming wellbores and wellheads.

Summary Of The Invention

According to one aspect of the present invention, an expansion cone for expanding a tubular member is provided that includes a housing including a tapered first end and a second end, one or more grooves formed in the outer surface of the tapered first end, and one or more axial flow passages fluidically coupled to the circumferential grooves.

According to another aspect of the present invention, a method of lubricating the interface between a tubular member and an expansion cone having a first tapered end and a second end during the radial expansion of the tubular member by the expansion cone, wherein the interface between the tubular member and the first tapered end of the expansion cone includes a leading edge portion and a trailing edge portion, is provided that includes injecting a lubricating fluid into the trailing edge portion.

According to another aspect of the present invention, a method of removing debris formed during the radial expansion of a tubular member by an expansion cone from the interface between the tubular member and the expansion cone, the expansion cone including a first tapered end and a second end, the interface between the tubular member and the first tapered end of the expansion cone includes a leading edge portion and a trailing edge portion, is provided that includes injecting a lubricating fluid into the interface between the tubular member and the expansion cone.

According to another aspect of the present invention, a tubular member is provided that includes an annular member having a wall thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member for radial expansions of up to about 25%.

According to another aspect of the present invention, a wellbore casing is provided that includes one or more tubular members. Each tubular member includes

an annular member having a wall thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %, imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member for radial expansions of up to about 25%.

5 According to another aspect of the present invention, a method of forming a wellbore casing is provided that includes placing a tubular member and an expansion cone in a wellbore and displacing the expansion cone relative to the tubular member. The tubular member includes an annular member having a wall thickness that varies less than about 8 %, a hoop yield strength that varies less than about 10 %,
10 imperfections of less than about 8 % of the wall thickness, no failure for radial expansions of up to about 30 %, and no necking of the walls of the annular member for radial expansions of up to about 25%.

 According to another aspect of the present invention, a method of selecting a group of tubular members for subsequent radial expansion is provided that includes
15 radially expanding the ends of a representative sample of the group of tubular members, measuring the amount of necking of the walls of the radially expanded ends of the tubular members, and if the radially expanded ends of the tubular members do not exhibit necking for radial expansions of up to about 25%, then accepting the group of tubular members.

20 According to another aspect of the present invention, a method of selecting a group of tubular members is provided that includes radially expanding the ends of a representative sample of the group of tubular members until each of the tubular members fail, and if the radially expanded ends of the tubular members do not fail for radial expansions of up to about 30%, then accepting the group of tubular
25 members.

 According to another aspect of the present invention, a method of inserting a tubular member into a wellbore is provided that includes injecting a lubricating fluid into the wellbore and inserting the tubular member into the wellbore.

Brief Description of the Drawings

FIG. 1 is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

5 FIG. 2 is a fragmentary cross-sectional view illustrating the placement of an embodiment of an apparatus for creating a casing within the new section of the well borehole.

FIG. 3 is a fragmentary cross-sectional view illustrating the injection of a first quantity of a fluidic material into the new section of the well borehole.

10 FIG. 3a is another fragmentary cross-sectional view illustrating the injection of a first quantity of a hardenable fluidic sealing material into the new section of the well borehole.

FIG. 4 is a fragmentary cross-sectional view illustrating the injection of a second quantity of a fluidic material into the new section of the well borehole.

15 FIG. 5 is a fragmentary cross-sectional view illustrating the drilling out of a portion of the cured hardenable fluidic sealing material from the new section of the well borehole.

FIG. 6 is a cross-sectional view of an embodiment of the overlapping joint between adjacent tubular members.

20 FIG. 7 is a fragmentary cross-sectional view of a preferred embodiment of the apparatus for creating a casing within a well borehole.

FIG. 8 is a fragmentary cross-sectional illustration of the placement of an expanded tubular member within another tubular member.

FIG. 9 is a cross-sectional illustration of a preferred embodiment of an apparatus for forming a casing including a drillable mandrel and shoe.

25 FIG. 9a is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 9b is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 9c is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 10a is a cross-sectional illustration of a wellbore including a pair of adjacent overlapping casings.

FIG. 12 is a cross-sectional illustration of a preferred embodiment of a wellhead system utilizing expandable tubular members.

FIG. 13 is a partial cross-sectional illustration of a preferred embodiment of the wellhead system of FIG. 12.

5 FIG. 14a is an illustration of the formation of an embodiment of a mono-diameter wellbore casing.

FIG. 14b is another illustration of the formation of the mono-diameter wellbore casing.

10 FIG. 14c is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14d is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14e is another illustration of the formation of the mono-diameter wellbore casing.

15 FIG. 14f is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 15 is an illustration of an embodiment of an apparatus for expanding a tubular member.

FIG. 15a is another illustration of the apparatus of FIG. 15.

20 FIG. 15b is another illustration of the apparatus of FIG. 15.

FIG. 16 is an illustration of an embodiment of an apparatus for forming a mono-diameter wellbore casing.

FIG. 17 is an illustration of an embodiment of an apparatus for expanding a tubular member.

25 FIG. 17a is another illustration of the apparatus of FIG. 16.

FIG. 17b is another illustration of the apparatus of FIG. 16.

FIG. 18 is an illustration of an embodiment of an apparatus for forming a mono-diameter wellbore casing.

FIG. 10b is a cross-sectional illustration of an apparatus and method for creating a tie-back liner using an expandable tubular member.

5 FIG. 10c is a cross-sectional illustration of the pumping of a fluidic sealing material into the annular region between the tubular member and the existing casing.

FIG. 10d is a cross-sectional illustration of the pressurizing of the interior of the tubular member below the mandrel.

FIG. 10e is a cross-sectional illustration of the extrusion of the tubular member off of the mandrel.

10 FIG. 10f is a cross-sectional illustration of the tie-back liner before drilling out the shoe and packer.

FIG. 10g is a cross-sectional illustration of the completed tie-back liner created using an expandable tubular member.

15 FIG. 11a is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 11b is a fragmentary cross-sectional view illustrating the placement of an embodiment of an apparatus for hanging a tubular liner within the new section of the well borehole.

20 FIG. 11c is a fragmentary cross-sectional view illustrating the injection of a first quantity of a hardenable fluidic sealing material into the new section of the well borehole.

FIG. 11d is a fragmentary cross-sectional view illustrating the introduction of a wiper dart into the new section of the well borehole.

25 FIG. 11e is a fragmentary cross-sectional view illustrating the injection of a second quantity of a hardenable fluidic sealing material into the new section of the well borehole.

FIG. 11f is a fragmentary cross-sectional view illustrating the completion of the tubular liner.

FIG. 19 is an illustration of another embodiment of an apparatus for expanding a tubular member.

FIG. 19a is another illustration of the apparatus of FIG. 17.

FIG. 19b is another illustration of the apparatus of FIG. 17.

5 FIG. 20 is an illustration of an embodiment of an apparatus for forming a mono-diameter wellbore casing.

FIG. 21 is an illustration of the isolation of subterranean zones using expandable tubulars.

10 FIG. 22a is a fragmentary cross-sectional illustration of an embodiment of an apparatus for forming a wellbore casing while drilling a wellbore.

FIG. 22b is another fragmentary cross-sectional illustration of the apparatus of FIG. 22a.

FIG. 22c is another fragmentary cross-sectional illustration of the apparatus of FIG. 22a.

15 FIG. 22d is another fragmentary cross-sectional illustration of the apparatus of FIG. 22a.

FIG. 23a is a fragmentary cross-section illustration of an embodiment of an apparatus and method for expanding tubular members.

20 FIG. 23b is another fragmentary cross-sectional illustration of the apparatus of FIG. 23a.

FIG. 23c is another fragmentary cross-sectional illustration of the apparatus of FIG. 23a.

FIG. 24a is a fragmentary cross-section illustration of an embodiment of an apparatus and method for expanding tubular members.

25 FIG. 24b is another fragmentary cross-sectional illustration of the apparatus of FIG. 24a.

FIG. 24c is another fragmentary cross-sectional illustration of the apparatus of FIG. 24a.

FIG. 24d is another fragmentary cross-sectional illustration of the apparatus of FIG. 24a.

FIG. 24e is another fragmentary cross-sectional illustration of the apparatus of FIG. 24a.

5 FIG. 25 is a partial cross-sectional illustration of an expansion mandrel expanding a tubular member.

FIG. 26 is a graphical illustration of the relationship between propagation pressure and the angle of attack of the expansion mandrel.

10 FIG. 27 is a cross-sectional illustration of an embodiment of an expandable connector.

FIG. 28 is a cross-sectional illustration of another embodiment of an expandable connector.

FIG. 29 is a cross-sectional illustration of another embodiment of an expandable connector.

15 FIG. 30 is a cross-sectional illustration of another embodiment of an expandable connector.

FIG. 31 is a fragmentary cross-sectional illustration of the lubrication of the interface between an expansion mandrel and a tubular member during the radial expansion process.

20 FIG. 32 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

25 FIG. 33 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 34 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 35 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

5 FIG. 36 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 37 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

10 FIG. 38 is an illustration of an embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

15 FIG. 39 is an illustration of a preferred embodiment of an expansion mandrel including a system for lubricating the interface between the expansion mandrel and a tubular member during the radial expansion of the tubular member.

FIG. 40 is a cross-sectional illustration of the first axial groove of the expansion mandrel of FIG. 39.

FIG. 41 is a cross-sectional illustration of the circumferential groove of the expansion mandrel of FIG. 39.

20 FIG. 42 is a cross-sectional illustration of one of the second axial grooves of the expansion mandrel of FIG. 39.

FIG. 43 is a cross sectional illustration of an embodiment of an expansion mandrel including internal flow passages having inserts for adjusting the flow of lubricant fluids.

25 FIG. 44 is a cross sectional illustration of the expansion mandrel of FIG. 43 further including an insert having a filter for filtering out foreign materials from the lubricant fluids.

FIG. 45 is a cross sectional illustration of a preferred embodiment of an expandible tubular for use in forming and/or repairing a wellbore casing, pipeline, or foundation support.

FIG. 46 is a cross sectional illustration of the flared end of a tubular member
5 selected for testing.

FIG. 47 is a cross sectional illustration of the flared end of a tubular member selected for testing that has structurally failed.

Detailed Description of the Illustrative Embodiments

An apparatus and method for forming a wellbore casing within a subterranean
10 formation is provided. The apparatus and method permits a wellbore casing to be formed in a subterranean formation by placing a tubular member and a mandrel in a new section of a wellbore, and then extruding the tubular member off of the mandrel by pressurizing an interior portion of the tubular member. The apparatus and method further permits adjacent tubular members in the wellbore to be joined
15 using an overlapping joint that prevents fluid and or gas passage. The apparatus and method further permits a new tubular member to be supported by an existing tubular member by expanding the new tubular member into engagement with the existing tubular member. The apparatus and method further minimizes the reduction in the hole size of the wellbore casing necessitated by the addition of new sections of
20 wellbore casing.

An apparatus and method for forming a tie-back liner using an expandable tubular member is also provided. The apparatus and method permits a tie-back liner to be created by extruding a tubular member off of a mandrel by pressurizing and interior portion of the tubular member. In this manner, a tie-back liner is produced.
25 The apparatus and method further permits adjacent tubular members in the wellbore to be joined using an overlapping joint that prevents fluid and/or gas passage. The apparatus and method further permits a new tubular member to be supported by an

existing tubular member by expanding the new tubular member into engagement with the existing tubular member.

5 An apparatus and method for expanding a tubular member is also provided that includes an expandable tubular member, mandrel and a shoe. In a preferred embodiment, the interior portions of the apparatus is composed of materials that permit the interior portions to be removed using a conventional drilling apparatus. In this manner, in the event of a malfunction in a downhole region, the apparatus may be easily removed.

10 An apparatus and method for hanging an expandable tubular liner in a wellbore is also provided. The apparatus and method permit a tubular liner to be attached to an existing section of casing. The apparatus and method further have application to the joining of tubular members in general.

15 An apparatus and method for forming a wellhead system is also provided. The apparatus and method permit a wellhead to be formed including a number of expandable tubular members positioned in a concentric arrangement. The wellhead preferably includes an outer casing that supports a plurality of concentric casings using contact pressure between the inner casings and the outer casing. The resulting wellhead system eliminates many of the spools conventionally required, reduces the height of the Christmas tree facilitating servicing, lowers the load bearing areas of the
20 wellhead resulting in a more stable system, and eliminates costly and expensive hanger systems.

25 An apparatus and method for forming a mono-diameter well casing is also provided. The apparatus and method permit the creation of a well casing in a wellbore having a substantially constant internal diameter. In this manner, the operation of an oil or gas well is greatly simplified.

An apparatus and method for expanding tubular members is also provided. The apparatus and method utilize a piston-cylinder configuration in which a pressurized chamber is used to drive a mandrel to radially expand tubular members. In this manner, higher operating pressures can be utilized. Throughout the radial

expansion process, the tubular member is never placed in direct contact with the operating pressures. In this manner, damage to the tubular member is prevented while also permitting controlled radial expansion of the tubular member in a wellbore.

5 An apparatus and method for forming a mono-diameter wellbore casing is also provided. The apparatus and method utilize a piston-cylinder configuration in which a pressurized chamber is used to drive a mandrel to radially expand tubular members. In this manner, higher operating pressures can be utilized. Throughout the radial expansion process, the tubular member is never placed in direct contact
10 with the operating pressures. In this manner, damage to the tubular member is prevented while also permitting controlled radial expansion of the tubular member in a wellbore.

 An apparatus and method for isolating one or more subterranean zones from one or more other subterranean zones is also provided. The apparatus and method
15 permits a producing zone to be isolated from a nonproducing zone using a combination of solid and slotted tubulars. In the production mode, the teachings of the present disclosure may be used in combination with conventional, well known, production completion equipment and methods using a series of packers, solid tubing, perforated tubing, and sliding sleeves, which will be inserted into the disclosed
20 apparatus to permit the commingling and/or isolation of the subterranean zones from each other.

 An apparatus and method for forming a wellbore casing while the wellbore is drilled is also provided. In this manner, a wellbore casing can be formed simultaneous with the drilling out of a new section of the wellbore. In a preferred
25 embodiment, the apparatus and method is used in combination with one or more of the apparatus and methods disclosed in the present disclosure for forming wellbore casings using expandable tubulars. Alternatively, the method and apparatus can be used to create a pipeline or tunnel in a time efficient manner.

An expandable connector is also provided. In a preferred implementation, the expandable connector is used in conjunction with one or more of the disclosed embodiments for expanding tubular members. In this manner, the expansion of a plurality of tubular members coupled to one another using the expandable connector is optimized.

A lubrication and self-cleaning system for an expansion cone is also provided. In a preferred implementation, the expansion cone includes one or more circumferential grooves and one or more axial grooves for providing a supply of lubricating fluid to the trailing edge portion of the interface between the expansion cone and a tubular member during the radial expansion process. In this manner, the frictional forces created during the radial expansion process are reduced which results in a reduction in the required operating pressures for radially expanding the tubular member. Furthermore, the supply of lubricating fluid preferably removes loose material from tapered end of the expansion cone that is formed during the radial expansion process.

A method of testing and selecting tubular members for radial expansion operations is also provided. In a preferred embodiment, the method provides tubular members that are optimally suited for radial expansion. In this manner, radially expanded tubular members having optimal structural properties are provided.

In several alternative embodiments, the apparatus and methods are used to form and/or repair wellbore casings, pipelines, and/or structural supports.

Referring initially to Figs. 1-5, an embodiment of an apparatus and method for forming a wellbore casing within a subterranean formation will now be described. As illustrated in Fig. 1, a wellbore 100 is positioned in a subterranean formation 105. The wellbore 100 includes an existing cased section 110 having a tubular casing 115 and an annular outer layer of cement 120.

In order to extend the wellbore 100 into the subterranean formation 105, a drill string 125 is used in a well known manner to drill out material from the subterranean formation 105 to form a new section 130.

As illustrated in Fig. 2, an apparatus 200 for forming a wellbore casing in a subterranean formation is then positioned in the new section 130 of the wellbore 100.

The apparatus 200 preferably includes an expandable mandrel or pig 205, a tubular member 210, a shoe 215, a lower cup seal 220, an upper cup seal 225, a fluid passage 230, a fluid passage 235, a fluid passage 240, seals 245, and a support member 250.

The expandable mandrel 205 is coupled to and supported by the support member 250. The expandable mandrel 205 is preferably adapted to controllably expand in a radial direction. The expandable mandrel 205 may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the expandable mandrel 205 comprises a hydraulic expansion tool as disclosed in U.S. Patent No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The tubular member 210 is supported by the expandable mandrel 205. The tubular member 210 is expanded in the radial direction and extruded off of the expandable mandrel 205. The tubular member 210 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, or plastic tubing/casing. In a preferred embodiment, the tubular member 210 is fabricated from OCTG in order to maximize strength after expansion. The inner and outer diameters of the tubular member 210 may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. In a preferred embodiment, the inner and outer diameters of the tubular member 210 range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most commonly drilled wellbore sizes. The tubular member 210 preferably comprises a solid member.

In a preferred embodiment, the end portion 260 of the tubular member 210 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 205 when it completes the extrusion of tubular member 210. In a preferred embodiment,

the length of the tubular member 210 is limited to minimize the possibility of buckling. For typical tubular member 210 materials, the length of the tubular member 210 is preferably limited to between about 40 to 20,000 feet in length.

5 The shoe 215 is coupled to the expandable mandrel 205 and the tubular member 210. The shoe 215 includes fluid passage 240. The shoe 215 may comprise any number of conventional commercially available shoes such as, for example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 215 comprises an aluminum down-
10 jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 210 in the wellbore, optimally provide an adequate seal between the interior and exterior diameters of the overlapping joint between the tubular members, and to optimally
15 allow the complete drill out of the shoe and plug after the completion of the cementing and expansion operations.

 In a preferred embodiment, the shoe 215 includes one or more through and side outlet ports in fluidic communication with the fluid passage 240. In this manner, the shoe 215 optimally injects hardenable fluidic sealing material into the region
20 outside the shoe 215 and tubular member 210. In a preferred embodiment, the shoe 215 includes the fluid passage 240 having an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage 240 can be optimally sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

25 The lower cup seal 220 is coupled to and supported by the support member 250. The lower cup seal 220 prevents foreign materials from entering the interior region of the tubular member 210 adjacent to the expandable mandrel 205. The lower cup seal 220 may comprise any number of conventional commercially available cup seals such as, for example, TP cups, or Selective Injection Packer (SIP) cups

modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the lower cup seal 220 comprises a SIP cup seal, available from Halliburton Energy Services in Dallas, TX in order to optimally block foreign material and contain a body of lubricant.

5 The upper cup seal 225 is coupled to and supported by the support member 250. The upper cup seal 225 prevents foreign materials from entering the interior region of the tubular member 210. The upper cup seal 225 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in accordance with the teachings of the present disclosure. In a
10 preferred embodiment, the upper cup seal 225 comprises a SIP cup, available from Halliburton Energy Services in Dallas, TX in order to optimally block the entry of foreign materials and contain a body of lubricant.

 The fluid passage 230 permits fluidic materials to be transported to and from the interior region of the tubular member 210 below the expandable mandrel 205.
15 The fluid passage 230 is coupled to and positioned within the support member 250 and the expandable mandrel 205. The fluid passage 230 preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel 205. The fluid passage 230 is preferably positioned along a centerline of the apparatus 200.

 The fluid passage 230 is preferably selected, in the casing running mode of
20 operation, to transport materials such as drilling mud or formation fluids at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to minimize drag on the tubular member being run and to minimize surge pressures exerted on the wellbore which could cause a loss of wellbore fluids and lead to hole collapse.

25 The fluid passage 235 permits fluidic materials to be released from the fluid passage 230. In this manner, during placement of the apparatus 200 within the new section 130 of the wellbore 100, fluidic materials 255 forced up the fluid passage 230 can be released into the wellbore 100 above the tubular member 210 thereby minimizing surge pressures on the wellbore section 130. The fluid passage 235 is

coupled to and positioned within the support member 250. The fluid passage is further fluidically coupled to the fluid passage 230.

5 The fluid passage 235 preferably includes a control valve for controllably opening and closing the fluid passage 235. In a preferred embodiment, the control valve is pressure activated in order to controllably minimize surge pressures. The fluid passage 235 is preferably positioned substantially orthogonal to the centerline of the apparatus 200.

10 The fluid passage 235 is preferably selected to convey fluidic materials at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to reduce the drag on the apparatus 200 during insertion into the new section 130 of the wellbore 100 and to minimize surge pressures on the new wellbore section 130.

15 The fluid passage 240 permits fluidic materials to be transported to and from the region exterior to the tubular member 210 and shoe 215. The fluid passage 240 is coupled to and positioned within the shoe 215 in fluidic communication with the interior region of the tubular member 210 below the expandable mandrel 205. The fluid passage 240 preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in fluid passage 240 to thereby block further passage of fluidic materials. In this manner, the interior region of the tubular member 210 below the expandable mandrel 205 can be fluidically isolated from the region exterior to the tubular member 210. This permits the interior region of the tubular member 210 below the expandable mandrel 205 to be pressurized. The fluid passage 240 is preferably positioned substantially along the centerline of the apparatus 200.

20 The fluid passage 240 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member 210 and the new section 130 of the wellbore 100 with fluidic materials. In a preferred embodiment, the fluid passage 240 includes an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the

fluid passage 240 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

5 The seals 245 are coupled to and supported by an end portion 260 of the tubular member 210. The seals 245 are further positioned on an outer surface 265 of the end portion 260 of the tubular member 210. The seals 245 permit the overlapping joint between the end portion 270 of the casing 115 and the portion 260 of the tubular member 210 to be fluidically sealed. The seals 245 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the seals 245 are molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a load bearing interference fit between the end 260 of the tubular member 210 and the end 270 of the existing casing 115.

10 In a preferred embodiment, the seals 245 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 210 from the existing casing 115. In a preferred embodiment, the frictional force optimally provided by the seals 245 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 210.

15 The support member 250 is coupled to the expandable mandrel 205, tubular member 210, shoe 215, and seals 220 and 225. The support member 250 preferably comprises an annular member having sufficient strength to carry the apparatus 200 into the new section 130 of the wellbore 100. In a preferred embodiment, the support member 250 further includes one or more conventional centralizers (not illustrated) to help stabilize the apparatus 200. In a preferred embodiment, the support member 250 comprises coiled tubing.

20 In a preferred embodiment, a quantity of lubricant 275 is provided in the annular region above the expandable mandrel 205 within the interior of the tubular member 210. In this manner, the extrusion of the tubular member 210 off of the expandable mandrel 205 is facilitated. The lubricant 275 may comprise any number

of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze (3100). In a preferred embodiment, the lubricant 275 comprises Climax 1500 Antisieze (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide optimum lubrication to facilitate the expansion process.

In a preferred embodiment, the support member 250 is thoroughly cleaned prior to assembly to the remaining portions of the apparatus 200. In this manner, the introduction of foreign material into the apparatus 200 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 200.

In a preferred embodiment, before or after positioning the apparatus 200 within the new section 130 of the wellbore 100, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore 100 that might clog up the various flow passages and valves of the apparatus 200 and to ensure that no foreign material interferes with the expansion process.

As illustrated in Fig. 3, the fluid passage 235 is then closed and a hardenable fluidic sealing material 305 is then pumped from a surface location into the fluid passage 230. The material 305 then passes from the fluid passage 230 into the interior region 310 of the tubular member 210 below the expandable mandrel 205. The material 305 then passes from the interior region 310 into the fluid passage 240. The material 305 then exits the apparatus 200 and fills the annular region 315 between the exterior of the tubular member 210 and the interior wall of the new section 130 of the wellbore 100. Continued pumping of the material 305 causes the material 305 to fill up at least a portion of the annular region 315.

The material 305 is preferably pumped into the annular region 315 at pressures and flow rates ranging, for example, from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively. The optimum flow rate and operating pressures vary as a function of the casing and wellbore sizes, wellbore section length, available pumping equipment, and fluid properties of the fluidic material being pumped. The optimum

flow rate and operating pressure are preferably determined using conventional empirical methods.

5 The hardenable fluidic sealing material 305 may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In a preferred embodiment, the hardenable fluidic sealing material 305 comprises a blended cement prepared specifically for the particular well section being drilled from Halliburton Energy Services in Dallas, TX in order to provide optimal support for tubular member 210 while also maintaining optimum flow characteristics so as to minimize difficulties during the displacement of cement in the annular region 315. The optimum blend of the blended cement is
10 preferably determined using conventional empirical methods.

 The annular region 315 preferably is filled with the material 305 in sufficient quantities to ensure that, upon radial expansion of the tubular member 210, the annular region 315 of the new section 130 of the wellbore 100 will be filled with
15 material 305.

 In a particularly preferred embodiment, as illustrated in Fig. 3a, the wall thickness and/or the outer diameter of the tubular member 210 is reduced in the region adjacent to the mandrel 205 in order optimally permit placement of the apparatus 200 in positions in the wellbore with tight clearances. Furthermore, in this
20 manner, the initiation of the radial expansion of the tubular member 210 during the extrusion process is optimally facilitated.

 As illustrated in Fig. 4, once the annular region 315 has been adequately filled with material 305, a plug 405, or other similar device, is introduced into the fluid passage 240 thereby fluidically isolating the interior region 310 from the annular region
25 315. In a preferred embodiment, a non-hardenable fluidic material 306 is then pumped into the interior region 310 causing the interior region to pressurize. In this manner, the interior of the expanded tubular member 210 will not contain significant amounts of cured material 305. This reduces and simplifies the cost of the entire process. Alternatively, the material 305 may be used during this phase of the process.

Once the interior region 310 becomes sufficiently pressurized, the tubular member 210 is extruded off of the expandable mandrel 205. During the extrusion process, the expandable mandrel 205 may be raised out of the expanded portion of the tubular member 210. In a preferred embodiment, during the extrusion process, the
5 mandrel 205 is raised at approximately the same rate as the tubular member 210 is expanded in order to keep the tubular member 210 stationary relative to the new wellbore section 130. In an alternative preferred embodiment, the extrusion process is commenced with the tubular member 210 positioned above the bottom of the new wellbore section 130, keeping the mandrel 205 stationary, and allowing the tubular
10 member 210 to extrude off of the mandrel 205 and fall down the new wellbore section 130 under the force of gravity.

The plug 405 is preferably placed into the fluid passage 240 by introducing the plug 405 into the fluid passage 230 at a surface location in a conventional manner. The plug 405 preferably acts to fluidically isolate the hardenable fluidic sealing material
15 305 from the non hardenable fluidic material 306.

The plug 405 may comprise any number of conventional commercially available devices from plugging a fluid passage such as, for example, Multiple Stage Cementer (MSC) latch-down plug, Omega latch-down plug or three-wiper latch-down plug modified in accordance with the teachings of the present disclosure. In a
20 preferred embodiment, the plug 405 comprises a MSC latch-down plug available from Halliburton Energy Services in Dallas, TX.

After placement of the plug 405 in the fluid passage 240, a non hardenable fluidic material 306 is preferably pumped into the interior region 310 at pressures and flow rates ranging, for example, from approximately 400 to 10,000 psi and 30 to
25 4,000 gallons/min. In this manner, the amount of hardenable fluidic sealing material within the interior 310 of the tubular member 210 is minimized. In a preferred embodiment, after placement of the plug 405 in the fluid passage 240, the non hardenable material 306 is preferably pumped into the interior region 310 at

pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to maximize the extrusion speed.

5 In a preferred embodiment, the apparatus 200 is adapted to minimize tensile, burst, and friction effects upon the tubular member 210 during the expansion process. These effects will depend upon the geometry of the expansion mandrel 205, the material composition of the tubular member 210 and expansion mandrel 205, the inner diameter of the tubular member 210, the wall thickness of the tubular member 210, the type of lubricant, and the yield strength of the tubular member 210. In general, the thicker the wall thickness, the smaller the inner diameter, and the greater the yield strength of the tubular member 210, then the greater the operating pressures required to extrude the tubular member 210 off of the mandrel 205.

10 For typical tubular members 210, the extrusion of the tubular member 210 off of the expandable mandrel will begin when the pressure of the interior region 310 reaches, for example, approximately 500 to 9,000 psi.

15 During the extrusion process, the expandable mandrel 205 may be raised out of the expanded portion of the tubular member 210 at rates ranging, for example, from about 0 to 5 ft/sec. In a preferred embodiment, during the extrusion process, the expandable mandrel 205 is raised out of the expanded portion of the tubular member 210 at rates ranging from about 0 to 2 ft/sec in order to minimize the time required for the expansion process while also permitting easy control of the expansion process.

20 When the end portion 260 of the tubular member 210 is extruded off of the expandable mandrel 205, the outer surface 265 of the end portion 260 of the tubular member 210 will preferably contact the interior surface 410 of the end portion 270 of the casing 115 to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50 to 20,000 psi. In a preferred embodiment, the contact pressure of the overlapping joint ranges from approximately 400 to 10,000 psi in order to provide optimum pressure to activate the

annular sealing members 245 and optimally provide resistance to axial motion to accommodate typical tensile and compressive loads.

5 The overlapping joint between the section 410 of the existing casing 115 and the section 265 of the expanded tubular member 210 preferably provides a gaseous and fluidic seal. In a particularly preferred embodiment, the sealing members 245 optimally provide a fluidic and gaseous seal in the overlapping joint.

10 In a preferred embodiment, the operating pressure and flow rate of the non hardenable fluidic material 306 is controllably ramped down when the expandable mandrel 205 reaches the end portion 260 of the tubular member 210. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 210 off of the expandable mandrel 205 can be minimized. In a preferred embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the mandrel 205 is within about 5 feet from completion of the extrusion process.

15 Alternatively, or in combination, a shock absorber is provided in the support member 250 in order to absorb the shock caused by the sudden release of pressure. The shock absorber may comprise, for example, any conventional commercially available shock absorber adapted for use in wellbore operations.

20 Alternatively, or in combination, a mandrel catching structure is provided in the end portion 260 of the tubular member 210 in order to catch or at least decelerate the mandrel 205.

25 Once the extrusion process is completed, the expandable mandrel 205 is removed from the wellbore 100. In a preferred embodiment, either before or after the removal of the expandable mandrel 205, the integrity of the fluidic seal of the overlapping joint between the upper portion 260 of the tubular member 210 and the lower portion 270 of the casing 115 is tested using conventional methods.

If the fluidic seal of the overlapping joint between the upper portion 260 of the tubular member 210 and the lower portion 270 of the casing 115 is satisfactory, then any uncured portion of the material 305 within the expanded tubular member 210 is

then removed in a conventional manner such as, for example, circulating the uncured material out of the interior of the expanded tubular member 210. The mandrel 205 is then pulled out of the wellbore section 130 and a drill bit or mill is used in combination with a conventional drilling assembly 505 to drill out any hardened material 305 within the tubular member 210. The material 305 within the annular region 315 is then allowed to cure.

As illustrated in Fig. 5, preferably any remaining cured material 305 within the interior of the expanded tubular member 210 is then removed in a conventional manner using a conventional drill string 505. The resulting new section of casing 510 includes the expanded tubular member 210 and an outer annular layer 515 of cured material 305. The bottom portion of the apparatus 200 comprising the shoe 215 and dart 405 may then be removed by drilling out the shoe 215 and dart 405 using conventional drilling methods.

In a preferred embodiment, as illustrated in Fig. 6, the upper portion 260 of the tubular member 210 includes one or more sealing members 605 and one or more pressure relief holes 610. In this manner, the overlapping joint between the lower portion 270 of the casing 115 and the upper portion 260 of the tubular member 210 is pressure-tight and the pressure on the interior and exterior surfaces of the tubular member 210 is equalized during the extrusion process.

In a preferred embodiment, the sealing members 605 are seated within recesses 615 formed in the outer surface 265 of the upper portion 260 of the tubular member 210. In an alternative preferred embodiment, the sealing members 605 are bonded or molded onto the outer surface 265 of the upper portion 260 of the tubular member 210. The pressure relief holes 610 are preferably positioned in the last few feet of the tubular member 210. The pressure relief holes reduce the operating pressures required to expand the upper portion 260 of the tubular member 210. This reduction in required operating pressure in turn reduces the velocity of the mandrel 205 upon the completion of the extrusion process. This reduction in velocity in turn

minimizes the mechanical shock to the entire apparatus 200 upon the completion of the extrusion process.

Referring now to Fig. 7, a particularly preferred embodiment of an apparatus 700 for forming a casing within a wellbore preferably includes an expandable mandrel or pig 705, an expandable mandrel or pig container 710, a tubular member 715, a float shoe 720, a lower cup seal 725, an upper cup seal 730, a fluid passage 735, a fluid passage 740, a support member 745, a body of lubricant 750, an overshot connection 755, another support member 760, and a stabilizer 765.

The expandable mandrel 705 is coupled to and supported by the support member 745. The expandable mandrel 705 is further coupled to the expandable mandrel container 710. The expandable mandrel 705 is preferably adapted to controllably expand in a radial direction. The expandable mandrel 705 may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the expandable mandrel 705 comprises a hydraulic expansion tool substantially as disclosed in U.S. Pat. No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The expandable mandrel container 710 is coupled to and supported by the support member 745. The expandable mandrel container 710 is further coupled to the expandable mandrel 705. The expandable mandrel container 710 may be constructed from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods, stainless steel, titanium or high strength steels. In a preferred embodiment, the expandable mandrel container 710 is fabricated from material having a greater strength than the material from which the tubular member 715 is fabricated. In this manner, the container 710 can be fabricated from a tubular material having a thinner wall thickness than the tubular member 210. This permits the container 710 to pass through tight clearances thereby facilitating its placement within the wellbore.

In a preferred embodiment, once the expansion process begins, and the thicker, lower strength material of the tubular member 715 is expanded, the outside diameter of the tubular member 715 is greater than the outside diameter of the container 710.

5 The tubular member 715 is coupled to and supported by the expandable mandrel 705. The tubular member 715 is preferably expanded in the radial direction and extruded off of the expandable mandrel 705 substantially as described above with reference to Figs. 1-6. The tubular member 715 may be fabricated from any number of materials such as, for example, Oilfield Country Tubular Goods (OCTG), automotive grade steel or plastics. In a preferred embodiment, the tubular member
10 715 is fabricated from OCTG.

In a preferred embodiment, the tubular member 715 has a substantially annular cross-section. In a particularly preferred embodiment, the tubular member 715 has a substantially circular annular cross-section.

The tubular member 715 preferably includes an upper section 805, an
15 intermediate section 810, and a lower section 815. The upper section 805 of the tubular member 715 preferably is defined by the region beginning in the vicinity of the mandrel container 710 and ending with the top section 820 of the tubular member 715. The intermediate section 810 of the tubular member 715 is preferably defined by the region beginning in the vicinity of the top of the mandrel container
20 710 and ending with the region in the vicinity of the mandrel 705. The lower section of the tubular member 715 is preferably defined by the region beginning in the vicinity of the mandrel 705 and ending at the bottom 825 of the tubular member 715.

In a preferred embodiment, the wall thickness of the upper section 805 of the tubular member 715 is greater than the wall thicknesses of the intermediate and
25 lower sections 810 and 815 of the tubular member 715 in order to optimally facilitate the initiation of the extrusion process and optimally permit the apparatus 700 to be positioned in locations in the wellbore having tight clearances.

The outer diameter and wall thickness of the upper section 805 of the tubular member 715 may range, for example, from about 1.05 to 48 inches and 1/8 to 2 inches, respectively. In a preferred embodiment, the outer diameter and wall thickness of the upper section 805 of the tubular member 715 range from about 3.5 to 16 inches and 3/8 to 1.5 inches, respectively.

The outer diameter and wall thickness of the intermediate section 810 of the tubular member 715 may range, for example, from about 2.5 to 50 inches and 1/16 to 1.5 inches, respectively. In a preferred embodiment, the outer diameter and wall thickness of the intermediate section 810 of the tubular member 715 range from about 3.5 to 19 inches and 1/8 to 1.25 inches, respectively.

The outer diameter and wall thickness of the lower section 815 of the tubular member 715 may range, for example, from about 2.5 to 50 inches and 1/16 to 1.25 inches, respectively. In a preferred embodiment, the outer diameter and wall thickness of the lower section 810 of the tubular member 715 range from about 3.5 to 19 inches and 1/8 to 1.25 inches, respectively. In a particularly preferred embodiment, the wall thickness of the lower section 815 of the tubular member 715 is further increased to increase the strength of the shoe 720 when drillable materials such as, for example, aluminum are used.

The tubular member 715 preferably comprises a solid tubular member. In a preferred embodiment, the end portion 820 of the tubular member 715 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 705 when it completes the extrusion of tubular member 715. In a preferred embodiment, the length of the tubular member 715 is limited to minimize the possibility of buckling. For typical tubular member 715 materials, the length of the tubular member 715 is preferably limited to between about 40 to 20,000 feet in length.

The shoe 720 is coupled to the expandable mandrel 705 and the tubular member 715. The shoe 720 includes the fluid passage 740. In a preferred embodiment, the shoe 720 further includes an inlet passage 830, and one or more jet ports 835. In a particularly preferred embodiment, the cross-sectional shape of the

inlet passage 830 is adapted to receive a latch-down dart, or other similar elements, for blocking the inlet passage 830. The interior of the shoe 720 preferably includes a body of solid material 840 for increasing the strength of the shoe 720. In a particularly preferred embodiment, the body of solid material 840 comprises aluminum.

The shoe 720 may comprise any number of conventional commercially available shoes such as, for example, Super Seal II Down-Jet float shoe, or guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 720 comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimize guiding the tubular member 715 in the wellbore, optimize the seal between the tubular member 715 and an existing wellbore casing, and to optimally facilitate the removal of the shoe 720 by drilling it out after completion of the extrusion process.

The lower cup seal 725 is coupled to and supported by the support member 745. The lower cup seal 725 prevents foreign materials from entering the interior region of the tubular member 715 above the expandable mandrel 705. The lower cup seal 725 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the lower cup seal 725 comprises a SIP cup, available from Halliburton Energy Services in Dallas, TX in order to optimally provide a debris barrier and hold a body of lubricant.

The upper cup seal 730 is coupled to and supported by the support member 760. The upper cup seal 730 prevents foreign materials from entering the interior region of the tubular member 715. The upper cup seal 730 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or Selective Injection Packer (SIP) cup modified in accordance with the teachings of the

present disclosure. In a preferred embodiment, the upper cup seal 730 comprises a SIP cup available from Halliburton Energy Services in Dallas, TX in order to optimally provide a debris barrier and contain a body of lubricant.

5 The fluid passage 735 permits fluidic materials to be transported to and from the interior region of the tubular member 715 below the expandable mandrel 705. The fluid passage 735 is fluidically coupled to the fluid passage 740. The fluid passage 735 is preferably coupled to and positioned within the support member 760, the support member 745, the mandrel container 710, and the expandable mandrel 705. The fluid passage 735 preferably extends from a position adjacent to the surface to 10 the bottom of the expandable mandrel 705. The fluid passage 735 is preferably positioned along a centerline of the apparatus 700. The fluid passage 735 is preferably selected to transport materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 40 to 3,000 gallons/minute and 500 to 9,000 psi in order to optimally provide sufficient operating pressures to extrude the 15 tubular member 715 off of the expandable mandrel 705.

As described above with reference to Figs. 1-6, during placement of the apparatus 700 within a new section of a wellbore, fluidic materials forced up the fluid passage 735 can be released into the wellbore above the tubular member 715. In a preferred embodiment, the apparatus 700 further includes a pressure release passage 20 that is coupled to and positioned within the support member 260. The pressure release passage is further fluidically coupled to the fluid passage 735. The pressure release passage preferably includes a control valve for controllably opening and closing the fluid passage. In a preferred embodiment, the control valve is pressure activated in order to controllably minimize surge pressures. The pressure release 25 passage is preferably positioned substantially orthogonal to the centerline of the apparatus 700. The pressure release passage is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 500 gallons/minute and 0 to 1,000 psi in order to reduce the drag on

the apparatus 700 during insertion into a new section of a wellbore and to minimize surge pressures on the new wellbore section.

5 The fluid passage 740 permits fluidic materials to be transported to and from the region exterior to the tubular member 715. The fluid passage 740 is preferably coupled to and positioned within the shoe 720 in fluidic communication with the interior region of the tubular member 715 below the expandable mandrel 705. The fluid passage 740 preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in the inlet 830 of the fluid passage 740 to thereby block further passage of fluidic materials. In this manner, the interior region of the tubular member 715 below the expandable mandrel 705 can be optimally fluidically isolated from the region exterior to the tubular member 715. This permits the interior region of the tubular member 715 below the expandable mandrel 205 to be pressurized.

10 The fluid passage 740 is preferably positioned substantially along the centerline of the apparatus 700. The fluid passage 740 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill an annular region between the tubular member 715 and a new section of a wellbore with fluidic materials. In a preferred embodiment, the fluid passage 740 includes an inlet passage 830 having a geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage 240 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

15 In a preferred embodiment, the apparatus 700 further includes one or more seals 845 coupled to and supported by the end portion 820 of the tubular member 715. The seals 845 are further positioned on an outer surface of the end portion 820 of the tubular member 715. The seals 845 permit the overlapping joint between an end portion of preexisting casing and the end portion 820 of the tubular member 715 to be fluidically sealed. The seals 845 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred

embodiment, the seals 845 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a hydraulic seal and a load bearing interference fit in the overlapping joint between the tubular member 715 and an existing casing with optimal load bearing capacity to support the tubular member 715.

In a preferred embodiment, the seals 845 are selected to provide a sufficient frictional force to support the expanded tubular member 715 from the existing casing. In a preferred embodiment, the frictional force provided by the seals 845 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 715.

The support member 745 is preferably coupled to the expandable mandrel 705 and the overshot connection 755. The support member 745 preferably comprises an annular member having sufficient strength to carry the apparatus 700 into a new section of a wellbore. The support member 745 may comprise any number of conventional commercially available support members such as, for example, steel drill pipe, coiled tubing or other high strength tubular modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the support member 745 comprises conventional drill pipe available from various steel mills in the United States.

In a preferred embodiment, a body of lubricant 750 is provided in the annular region above the expandable mandrel container 710 within the interior of the tubular member 715. In this manner, the extrusion of the tubular member 715 off of the expandable mandrel 705 is facilitated. The lubricant 750 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants, or Climax 1500 Antisieze (3100). In a preferred embodiment, the lubricant 750 comprises Climax 1500 Antisieze (3100) available from Halliburton Energy Services in Houston, TX in order to optimally provide lubrication to facilitate the extrusion process.

5 The overshot connection 755 is coupled to the support member 745 and the support member 760. The overshot connection 755 preferably permits the support member 745 to be removably coupled to the support member 760. The overshot connection 755 may comprise any number of conventional commercially available overshot connections such as, for example, Innerstring Sealing Adapter, Innerstring Flat-Face Sealing Adapter or EZ Drill Setting Tool Stinger. In a preferred embodiment, the overshot connection 755 comprises a Innerstring Adapter with an Upper Guide available from Halliburton Energy Services in Dallas, TX.

10 The support member 760 is preferably coupled to the overshot connection 755 and a surface support structure (not illustrated). The support member 760 preferably comprises an annular member having sufficient strength to carry the apparatus 700 into a new section of a wellbore. The support member 760 may comprise any number of conventional commercially available support members such as, for example, steel drill pipe, coiled tubing or other high strength tubulars modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the support member 760 comprises a conventional drill pipe available from steel mills in the United States.

20 The stabilizer 765 is preferably coupled to the support member 760. The stabilizer 765 also preferably stabilizes the components of the apparatus 700 within the tubular member 715. The stabilizer 765 preferably comprises a spherical member having an outside diameter that is about 80 to 99% of the interior diameter of the tubular member 715 in order to optimally minimize buckling of the tubular member 715. The stabilizer 765 may comprise any number of conventional commercially available stabilizers such as, for example, EZ Drill Star Guides, packer shoes or drag blocks modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the stabilizer 765 comprises a sealing adapter upper guide available from Halliburton Energy Services in Dallas, TX.

25 In a preferred embodiment, the support members 745 and 760 are thoroughly cleaned prior to assembly to the remaining portions of the apparatus 700. In this

manner, the introduction of foreign material into the apparatus 700 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 700.

5 In a preferred embodiment, before or after positioning the apparatus 700 within a new section of a wellbore, a couple of wellbore volumes are circulated through the various flow passages of the apparatus 700 in order to ensure that no foreign materials are located within the wellbore that might clog up the various flow passages and valves of the apparatus 700 and to ensure that no foreign material interferes with the expansion mandrel 705 during the expansion process.

10 In a preferred embodiment, the apparatus 700 is operated substantially as described above with reference to Figs. 1-7 to form a new section of casing within a wellbore.

As illustrated in Fig. 8, in an alternative preferred embodiment, the method and apparatus described herein is used to repair an existing wellbore casing 805 by forming a tubular liner 810 inside of the existing wellbore casing 805. In a preferred embodiment, an outer annular lining of cement is not provided in the repaired section. In the alternative preferred embodiment, any number of fluidic materials can be used to expand the tubular liner 810 into intimate contact with the damaged section of the wellbore casing such as, for example, cement, epoxy, slag mix, or drilling mud. In the alternative preferred embodiment, sealing members 815 are preferably provided at both ends of the tubular member in order to optimally provide a fluidic seal. In an alternative preferred embodiment, the tubular liner 810 is formed within a horizontally positioned pipeline section, such as those used to transport hydrocarbons or water, with the tubular liner 810 placed in an overlapping relationship with the adjacent pipeline section. In this manner, underground pipelines can be repaired without having to dig out and replace the damaged sections.

25 In another alternative preferred embodiment, the method and apparatus described herein is used to directly line a wellbore with a tubular liner 810. In a preferred embodiment, an outer annular lining of cement is not provided between the

tubular liner 810 and the wellbore. In the alternative preferred embodiment, any number of fluidic materials can be used to expand the tubular liner 810 into intimate contact with the wellbore such as, for example, cement, epoxy, slag mix, or drilling mud.

5 Referring now to Figs. 9, 9a, 9b and 9c, a preferred embodiment of an apparatus 900 for forming a wellbore casing includes an expandable tubular member 902, a support member 904, an expandable mandrel or pig 906, and a shoe 908. In a preferred embodiment, the design and construction of the mandrel 906 and shoe 908 permits easy removal of those elements by drilling them out. In this manner, the
10 assembly 900 can be easily removed from a wellbore using a conventional drilling apparatus and corresponding drilling methods.

The expandable tubular member 902 preferably includes an upper portion 910, an intermediate portion 912 and a lower portion 914. During operation of the apparatus 900, the tubular member 902 is preferably extruded off of the mandrel 906
15 by pressurizing an interior region 966 of the tubular member 902. The tubular member 902 preferably has a substantially annular cross-section.

In a particularly preferred embodiment, an expandable tubular member 915 is coupled to the upper portion 910 of the expandable tubular member 902. During operation of the apparatus 900, the tubular member 915 is preferably extruded off of
20 the mandrel 906 by pressurizing the interior region 966 of the tubular member 902. The tubular member 915 preferably has a substantially annular cross-section. In a preferred embodiment, the wall thickness of the tubular member 915 is greater than the wall thickness of the tubular member 902.

The tubular member 915 may be fabricated from any number of conventional
25 commercially available materials such as, for example, oilfield tubulars, low alloy steels, titanium or stainless steels. In a preferred embodiment, the tubular member 915 is fabricated from oilfield tubulars in order to optimally provide approximately the same mechanical properties as the tubular member 902. In a particularly preferred embodiment, the tubular member 915 has a plastic yield point ranging from

5 wall casing 1510. The contact pressure of the interface between the intermediate casing 1530 and the thick wall casing 1510 may range, for example from about 500 to 10,000 psi. In a preferred embodiment, the contact pressure between the intermediate casing 1530 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the pressure activated sealing members and to optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads experienced during drilling and production operations.

10 As illustrated in Fig. 13, in a particularly preferred embodiment, the upper end of the intermediate casing 1530 includes one or more sealing members 1560 that provide a gaseous and fluidic seal between the expanded end of the intermediate casing 1530 and the interior wall of the thick wall casing 1510. The sealing members 1560 may comprise any number of conventional commercially available seals such as, for example, plastic, lead, rubber, Teflon or epoxy, modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the sealing members 15 1560 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in order to optimally provide a hydraulic seal and a load bearing interference fit between the tubular members.

20 In a preferred embodiment, the contact pressure of the interface between the expanded end of the intermediate casing 1530 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the sealing members 1560 and also optimally ensure that the joint will withstand typical operating extremes of tensile and compressive loads that are experienced during drilling and production operations.

25 The inner casing 1535 may be coupled to the outer casing 1520 or the thick wall casing 1510. In a preferred embodiment, the inner casing 1535 is coupled to the thick wall casing 1510. The inner casing 1535 may be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the inner casing

1535 comprises any one of the expandable tubular members described above with reference to Figs. 1-11f.

In a preferred embodiment, the inner casing 1535 is coupled to the outer casing 1520 by expanding at least a portion of the inner casing 1535 into contact with the interior surface of the thick wall casing 1510 using any one of the processes and apparatus described above with reference to Figs. 1-11f. In an alternative preferred embodiment, the entire length of the overlap of the inner casing 1535 with the thick wall casing 1510 and intermediate casing 1530 contacts the inner surfaces of the thick wall casing 1510 and intermediate casing 1530. The contact pressure of the interface between the inner casing 1535 and the thick wall casing 1510 may range, for example from about 500 to 10,000 psi. In a preferred embodiment, the contact pressure between the inner casing 1535 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the pressure activated sealing members and to ensure that the joint will withstand typical extremes of tensile and compressive loads that are commonly experienced during drilling and production operations.

As illustrated in Fig. 13, in a particularly preferred embodiment, the upper end of the inner casing 1535 includes one or more sealing members 1570 that provide a gaseous and fluidic seal between the expanded end of the inner casing 1535 and the interior wall of the thick wall casing 1510. The sealing members 1570 may comprise any number of conventional commercially available seals such as, for example, lead, plastic, rubber, Teflon or epoxy, modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the sealing members 1570 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal and a load bearing interference fit. In a preferred embodiment, the contact pressure of the interface between the expanded end of the inner casing 1535 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the sealing members 1570 and also to optimally ensure that the joint will withstand typical operating extremes of tensile

and compressive loads that are experienced during drilling and production operations.

5 In an alternative embodiment, the inner casings, 1520, 1530 and 1535, may be coupled to a previously positioned tubular member that is in turn coupled to the outer casing 1510. More generally, the present preferred embodiments may be used to form a concentric arrangement of tubular members.

Referring now to Figures 14a, 14b, 14c, 14d, 14e and 14f, a preferred embodiment of a method and apparatus for forming a mono-diameter well casing within a subterranean formation will now be described.

10 As illustrated in Fig. 14a, a wellbore 1600 is positioned in a subterranean formation 1605. A first section of casing 1610 is formed in the wellbore 1600. The first section of casing 1610 includes an annular outer body of cement 1615 and a tubular section of casing 1620. The first section of casing 1610 may be formed in the wellbore 1600 using conventional methods and apparatus. In a preferred
15 embodiment, the first section of casing 1610 is formed using one or more of the methods and apparatus described above with reference to Figs. 1-13 or below with reference to Figs. 14b-17b.

The annular body of cement 1615 may comprise any number of conventional commercially available cement, or other load bearing, compositions. Alternatively,
20 the body of cement 1615 may be omitted or replaced with an epoxy mixture.

The tubular section of casing 1620 preferably includes an upper end 1625 and a lower end 1630. Preferably, the lower end 1625 of the tubular section of casing 1620 includes an outer annular recess 1635 extending from the lower end 1630 of the tubular section of casing 1620. In this manner, the lower end 1625 of the tubular
25 section of casing 1620 includes a thin walled section 1640. In a preferred embodiment, an annular body 1645 of a compressible material is coupled to and at least partially positioned within the outer annular recess 1635. In this manner, the body of compressible material 1645 surrounds at least a portion of the thin walled section 1640.

The tubular section of casing 1620 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, automotive grade steel, carbon steel, low alloy steel, fiberglass or plastics. In a preferred embodiment, the tubular section of casing 1620 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills. The wall thickness of the thin walled section 1640 may range from about 0.125 to 1.5 inches. In a preferred embodiment, the wall thickness of the thin walled section 1640 ranges from 0.25 to 1.0 inches in order to optimally provide burst strength for typical operational conditions while also minimizing resistance to radial expansion. The axial length of the thin walled section 1640 may range from about 120 to 2400 inches. In a preferred embodiment, the axial length of the thin walled section 1640 ranges from about 240 to 480 inches.

The annular body of compressible material 1645 helps to minimize the radial force required to expand the tubular casing 1620 in the overlap with the tubular member 1715, helps to create a fluidic seal in the overlap with the tubular member 1715, and helps to create an interference fit sufficient to permit the tubular member 1715 to be supported by the tubular casing 1620. The annular body of compressible material 1645 may comprise any number of commercially available compressible materials such as, for example, epoxy, rubber, Teflon, plastics or lead tubes. In a preferred embodiment, the annular body of compressible material 1645 comprises StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal in the overlapped joint while also having compliance to thereby minimize the radial force required to expand the tubular casing. The wall thickness of the annular body of compressible material 1645 may range from about 0.05 to 0.75 inches. In a preferred embodiment, the wall thickness of the annular body of compressible material 1645 ranges from about 0.1 to 0.5 inches in order to optimally provide a large compressible zone, minimize the radial forces required to expand the tubular casing, provide thickness for casing strings to provide contact

with the inner surface of the wellbore upon radial expansion, and provide an hydraulic seal.

As illustrated in Fig. 14b, in order to extend the wellbore 1600 into the subterranean formation 1605, a drill string is used in a well known manner to drill
5 out material from the subterranean formation 1605 to form a new wellbore section 1650. The diameter of the new section 1650 is preferably equal to or greater than the inner diameter of the tubular section of casing 1620.

As illustrated in Fig. 14c, a preferred embodiment of an apparatus 1700 for forming a mono-diameter wellbore casing in a subterranean formation is then
10 positioned in the new section 1650 of the wellbore 1600. The apparatus 1700 preferably includes a support member 1705, an expandable mandrel or pig 1710, a tubular member 1715, a shoe 1720, slips 1725, a fluid passage 1730, one or more fluid passages 1735, a fluid passage 1740, a first compressible annular body 1745, a second compressible annular body 1750, and a pressure chamber 1755.

15 The support member 1705 supports the apparatus 1700 within the wellbore 1600. The support member 1705 is coupled to the mandrel 1710, the tubular member 1715, the shoe 1720, and the slips 1725. The support member 1075 preferably comprises a substantially hollow tubular member. The fluid passage 1730 is positioned within the support member 1705. The fluid passages 1735 fluidically couple
20 the fluid passage 1730 with the pressure chamber 1755. The fluid passage 1740 fluidically couples the fluid passage 1730 with the region outside of the apparatus 1700.

The support member 1705 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, low alloy steel, carbon steel, 13 chromium steel, fiberglass, or other
25 high strength materials. In a preferred embodiment, the support member 1705 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide operational strength and facilitate the use of other standard oil exploration handling equipment. In a preferred embodiment, at least a portion of the support member 1705 comprises coiled tubing

or a drill pipe. In a particularly preferred embodiment, the support member 1705 includes a load shoulder 1820 for supporting the mandrel 1710 when the pressure chamber 1755 is unpressurized.

5 The mandrel 1710 is supported by and slidingly coupled to the support member 1705 and the shoe 1720. The mandrel 1710 preferably includes an upper portion 1760 and a lower portion 1765. Preferably, the upper portion 1760 of the mandrel 1710 and the support member 1705 together define the pressure chamber 1755. Preferably, the lower portion 1765 of the mandrel 1710 includes an expansion member 1770 for radially expanding the tubular member 1715.

10 In a preferred embodiment, the upper portion 1760 of the mandrel 1710 includes a tubular member 1775 having an inner diameter greater than an outer diameter of the support member 1705. In this manner, an annular pressure chamber 1755 is defined by and positioned between the tubular member 1775 and the support member 1705. The top 1780 of the tubular member 1775 preferably includes a bearing and a seal for sealing and supporting the top 1780 of the tubular member 1775 against the outer surface of the support member 1705. The bottom 1785 of the tubular member 1775 preferably includes a bearing and seal for sealing and supporting the bottom 1785 of the tubular member 1775 against the outer surface of the support member 1705 or shoe 1720. In this manner, the mandrel 1710 moves in an axial direction upon the pressurization of the pressure chamber 1755.

20 The lower portion 1765 of the mandrel 1710 preferably includes an expansion member 1770 for radially expanding the tubular member 1715 during the pressurization of the pressure chamber 1755. In a preferred embodiment, the expansion member is expandable in the radial direction. In a preferred embodiment, 25 the inner surface of the lower portion 1765 of the mandrel 1710 mates with and slides with respect to the outer surface of the shoe 1720. The outer diameter of the expansion member 1770 may range from about 90 to 100 % of the inner diameter of the tubular casing 1620. In a preferred embodiment, the outer diameter of the expansion member 1770 ranges from about 95 to 99 % of the inner diameter of the

tubular casing 1620. The expansion member 1770 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, ceramics, tungsten carbide, titanium or other high strength alloys. In a preferred embodiment, the expansion member 1770 is fabricated from D2 machine tool steel in order to optimally provide high strength and abrasion resistance.

The tubular member 1715 is coupled to and supported by the support member 1705 and slips 1725. The tubular member 1715 includes an upper portion 1790 and a lower portion 1795.

10 The upper portion 1790 of the tubular member 1715 preferably includes an inner annular recess 1800 that extends from the upper portion 1790 of the tubular member 1715. In this manner, at least a portion of the upper portion 1790 of the tubular member 1715 includes a thin walled section 1805. The first compressible annular member 1745 is preferably coupled to and supported by the outer surface of
15 the upper portion 1790 of the tubular member 1715 in opposing relation to the thin wall section 1805.

 The lower portion 1795 of the tubular member 1715 preferably includes an outer annular recess 1810 that extends from the lower portion 1790 of the tubular member 1715. In this manner, at least a portion of the lower portion 1795 of the
20 tubular member 1715 includes a thin walled section 1815. The second compressible annular member 1750 is coupled to and at least partially supported within the outer annular recess 1810 of the upper portion 1790 of the tubular member 1715 in opposing relation to the thin wall section 1815.

 The tubular member 1715 may be fabricated from any number of conventional
25 commercially available materials such as, for example, oilfield country tubular goods, stainless steel, low alloy steel, carbon steel, automotive grade steel, fiberglass, 13 chrome steel, other high strength material, or high strength plastics. In a preferred embodiment, the tubular member 1715 is fabricated from oilfield country tubular

goods available from various foreign and domestic steel mills in order to optimally provide operational strength.

The shoe 1720 is supported by and coupled to the support member 1705. The shoe 1720 preferably comprises a substantially hollow tubular member. In a preferred embodiment, the wall thickness of the shoe 1720 is greater than the wall thickness of the support member 1705 in order to optimally provide increased radial support to the mandrel 1710. The shoe 1720 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, automotive grade steel, low alloy steel, carbon steel, or high strength plastics. In a preferred embodiment, the shoe 1720 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide matching operational strength throughout the apparatus.

The slips 1725 are coupled to and supported by the support member 1705. The slips 1725 removably support the tubular member 1715. In this manner, during the radial expansion of the tubular member 1715, the slips 1725 help to maintain the tubular member 1715 in a substantially stationary position by preventing upward movement of the tubular member 1715.

The slips 1725 may comprise any number of conventional commercially available slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips, or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In a preferred embodiment, the slips 1725 comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services. In a preferred embodiment, the slips 1725 are adapted to support axial forces ranging from about 0 to 750,000 lbf.

The fluid passage 1730 conveys fluidic materials from a surface location into the interior of the support member 1705, the pressure chamber 1755, and the region exterior of the apparatus 1700. The fluid passage 1730 is fluidically coupled to the

pressure chamber 1755 by the fluid passages 1735. The fluid passage 1730 is fluidically coupled to the region exterior to the apparatus 1700 by the fluid passage 1740.

In a preferred embodiment, the fluid passage 1730 is adapted to convey fluidic materials such as, for example, cement, epoxy, drilling muds, slag mix, water or drilling gasses. In a preferred embodiment, the fluid passage 1730 is adapted to convey fluidic materials at flow rate and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi. in order to optimally provide flow rates and operational pressures for the radial expansion processes.

The fluid passages 1735 convey fluidic material from the fluid passage 1730 to the pressure chamber 1755. In a preferred embodiment, the fluid passage 1735 is adapted to convey fluidic materials such as, for example, cement, epoxy, drilling muds, water or drilling gasses. In a preferred embodiment, the fluid passage 1735 is adapted to convey fluidic materials at flow rate and pressures ranging from about 0 to 500 gallons/minute and 0 to 9,000 psi. in order to optimally provide operating pressures and flow rates for the various expansion processes.

The fluid passage 1740 conveys fluidic materials from the fluid passage 1730 to the region exterior to the apparatus 1700. In a preferred embodiment, the fluid passage 1740 is adapted to convey fluidic materials such as, for example, cement, epoxy, drilling muds, water or drilling gasses. In a preferred embodiment, the fluid passage 1740 is adapted to convey fluidic materials at flow rate and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi. in order to optimally provide operating pressures and flow rates for the various radial expansion processes.

In a preferred embodiment, the fluid passage 1740 is adapted to receive a plug or other similar device for sealing the fluid passage 1740. In this manner, the pressure chamber 1755 may be pressurized.

The first compressible annular body 1745 is coupled to and supported by an exterior surface of the upper portion 1790 of the tubular member 1715. In a preferred embodiment, the first compressible annular body 1745 is positioned in opposing relation to the thin walled section 1805 of the tubular member 1715.

5 The first compressible annular body 1745 helps to minimize the radial force required to expand the tubular member 1715 in the overlap with the tubular casing 1620, helps to create a fluidic seal in the overlap with the tubular casing 1620, and helps to create an interference fit sufficient to permit the tubular member 1715 to be supported by the tubular casing 1620. The first compressible annular body 1745 may comprise any number of commercially available compressible materials such as, for example, epoxy, rubber, Teflon, plastics, or hollow lead tubes. In a preferred embodiment, the first compressible annular body 1745 comprises StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal, and compressibility to minimize the radial expansion force.

10 The wall thickness of the first compressible annular body 1745 may range from about 0.05 to 0.75 inches. In a preferred embodiment, the wall thickness of the first compressible annular body 1745 ranges from about 0.1 to 0.5 inches in order to optimally (1) provide a large compressible zone, (2) minimize the required radial expansion force, (3) transfer the radial force to the tubular casings. As a result, in a preferred embodiment, overall the outer diameter of the tubular member 1715 is approximately equal to the overall inner diameter of the tubular member 1620.

15 The second compressible annular body 1750 is coupled to and at least partially supported within the outer annular recess 1810 of the tubular member 1715. In a preferred embodiment, the second compressible annular body 1750 is positioned in opposing relation to the thin walled section 1815 of the tubular member 1715.

20 The second compressible annular body 1750 helps to minimize the radial force required to expand the tubular member 1715 in the overlap with another tubular member, helps to create a fluidic seal in the overlap of the tubular member 1715 with another tubular member, and helps to create an interference fit sufficient to permit another tubular member to be supported by the tubular member 1715. The second compressible annular body 1750 may comprise any number of commercially available compressible materials such as, for example, epoxy, rubber, Teflon, plastics or hollow lead tubing. In a preferred embodiment, the first compressible annular body 1750

comprises StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal in the overlapped joint, and compressibility that minimizes the radial expansion force.

5 The wall thickness of the second compressible annular body 1750 may range from about 0.05 to 0.75 inches. In a preferred embodiment, the wall thickness of the second compressible annular body 1750 ranges from about 0.1 to 0.5 inches in order to optimally provide a large compressible zone, and minimize the radial force required to expand the tubular member 1715 during subsequent radial expansion operations.

10 In an alternative embodiment, the outside diameter of the second compressible annular body 1750 is adapted to provide a seal against the surrounding formation thereby eliminating the need for an outer annular body of cement.

The pressure chamber 1755 is fluidly coupled to the fluid passage 1730 by the fluid passages 1735. The pressure chamber 1755 is preferably adapted to receive fluidic materials such as, for example, drilling muds, water or drilling gases. In a preferred embodiment, the pressure chamber 1755 is adapted to receive fluidic materials at flow rate and pressures ranging from about 0 to 500 gallons/minute and 0 to 9,000 psi. in order to optimally provide expansion pressure. In a preferred embodiment, during pressurization of the pressure chamber 1755, the operating pressure of the pressure chamber ranges from about 0 to 5,000 psi in order to optimally provide expansion pressure while minimizing the possibility of a catastrophic failure due to over pressurization.

20 As illustrated in Fig. 14d, the apparatus 1700 is preferably positioned in the wellbore 1600 with the tubular member 1715 positioned in an overlapping relationship with the tubular casing 1620. In a particularly preferred embodiment, the thin wall sections, 1640 and 1805, of the tubular casing 1620 and tubular member 1725 are positioned in opposing overlapping relation. In this manner, the radial expansion of the tubular member 1725 will compress the thin wall sections, 1640 and 1805, and annular compressible members, 1645 and 1745, into intimate contact.

After positioning of the apparatus 1700, a fluidic material 1825 is then pumped into the fluid passage 1730. The fluidic material 1825 may comprise any number of conventional commercially available materials such as, for example, water, drilling mud, drilling gases, cement or epoxy. In a preferred embodiment, the fluidic material 1825 comprises a hardenable fluidic sealing material such as, for example, cement in order to provide an outer annular body around the expanded tubular member 1715.

The fluidic material 1825 may be pumped into the fluid passage 1730 at operating pressures and flow rates, for example, ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The fluidic material 1825 pumped into the fluid passage 1730 passes through the fluid passage 1740 and outside of the apparatus 1700. The fluidic material 1825 fills the annular region 1830 between the outside of the apparatus 1700 and the interior walls of the wellbore 1600.

As illustrated in Fig. 14e, a plug 1835 is then introduced into the fluid passage 1730. The plug 1835 lodges in the inlet to the fluid passage 1740 fluidically isolating and blocking off the fluid passage 1730.

A fluidic material 1840 is then pumped into the fluid passage 1730. The fluidic material 1840 may comprise any number of conventional commercially available materials such as, for example, water, drilling mud or drilling gases. In a preferred embodiment, the fluidic material 1825 comprises a non-hardenable fluidic material such as, for example, drilling mud or drilling gases in order to optimally provide pressurization of the pressure chamber 1755.

The fluidic material 1840 may be pumped into the fluid passage 1730 at operating pressures and flow rates ranging, for example, from about 0 to 9,000 psi and 0 to 500 gallons/minute. In a preferred embodiment, the fluidic material 1840 is pumped into the fluid passage 1730 at operating pressures and flow rates ranging from about 500 to 5,000 psi and 0 to 500 gallons/minute in order to optimally provide operating pressures and flow rates for radial expansion.

The fluidic material 1840 pumped into the fluid passage 1730 passes through the fluid passages 1735 and into the pressure chamber 1755. Continued pumping of the fluidic material 1840 pressurizes the pressure chamber 1755. The pressurization of the pressure chamber 1755 causes the mandrel 1710 to move relative to the support member 1705 in the direction indicated by the arrows 1845. In this manner, the mandrel 1710 will cause the tubular member 1715 to expand in the radial direction.

During the radial expansion process, the tubular member 1715 is prevented from moving in an upward direction by the slips 1725. A length of the tubular member 1715 is then expanded in the radial direction through the pressurization of the pressure chamber 1755. The length of the tubular member 1715 that is expanded during the expansion process will be proportional to the stroke length of the mandrel 1710. Upon the completion of a stroke, the operating pressure of the pressure chamber 1755 is then reduced and the mandrel 1710 drops to its rest position with the tubular member 1715 supported by the mandrel 1715. The position of the support member 1705 may be adjusted throughout the radial expansion process in order to maintain the overlapping relationship between the thin walled sections, 1640 and 1805, of the tubular casing 1620 and tubular member 1715. The stroking of the mandrel 1710 is then repeated, as necessary, until the thin walled section 1805 of the tubular member 1715 is expanded into the thin walled section 1640 of the tubular casing 1620.

In a preferred embodiment, during the final stroke of the mandrel 1710, the slips 1725 are positioned as close as possible to the thin walled section 1805 of the tubular member 1715 in order to minimize slippage between the tubular member 1715 and tubular casing 1620 at the end of the radial expansion process. Alternatively, or in addition, the outside diameter of the first compressive annular member 1745 is selected to ensure sufficient interference fit with the tubular casing 1620 to prevent axial displacement of the tubular member 1715 during the final stroke. Alternatively, or in addition, the outside diameter of the second compressive annular body 1750 is

large enough to provide an interference fit with the inside walls of the wellbore 1600 at an earlier point in the radial expansion process so as to prevent further axial displacement of the tubular member 1715. In this final alternative, the interference fit is preferably selected to permit expansion of the tubular member 1715 by pulling
5 the mandrel 1710 out of the wellbore 1600, without having to pressurize the pressure chamber 1755.

During the radial expansion process, the pressurized areas of the apparatus 1700 are limited to the fluid passages 1730 within the support member 1705 and the pressure chamber 1755 within the mandrel 1710. No fluid pressure acts directly on
10 the tubular member 1715. This permits the use of operating pressures higher than the tubular member 1715 could normally withstand.

Once the tubular member 1715 has been completely expanded off of the mandrel 1710, the support member 1705 and mandrel 1710 are removed from the wellbore 1600. In a preferred embodiment, the contact pressure between the
15 deformed thin wall sections, 1640 and 1805, and compressible annular members, 1645 and 1745, ranges from about 400 to 10,000 psi in order to optimally support the tubular member 1715 using the tubular casing 1620.

In this manner, the tubular member 1715 is radially expanded into contact with the tubular casing 1620 by pressurizing the interior of the fluid passage 1730
20 and the pressure chamber 1755.

As illustrated in Fig. 14f, in a preferred embodiment, once the tubular member 1715 is completely expanded in the radial direction by the mandrel 1710, the support member 1705 and mandrel 1710 are removed from the wellbore 1600. In a preferred
25 embodiment, the annular body of hardenable fluidic material is then allowed to cure to form a rigid outer annular body 1850. In the case where the tubular member 1715 is slotted, the hardenable fluidic material will preferably permeate and envelop the expanded tubular member 1715.

The resulting new section of wellbore casing 1855 includes the expanded tubular member 1715 and the rigid outer annular body 1850. The overlapping joint

1860 between the tubular casing 1620 and the expanded tubular member 1715 includes the deformed thin wall sections, 1640 and 1805, and the compressible annular bodies, 1645 and 1745. The inner diameter of the resulting combined wellbore casings is substantially constant. In this manner, a mono-diameter wellbore casing is formed. This process of expanding overlapping tubular members having thin wall end portions with compressible annular bodies into contact can be repeated for the entire length of a wellbore. In this manner, a mono-diameter wellbore casing can be provided for thousands of feet in a subterranean formation.

Referring now to Figures 15, 15a and 15b, an embodiment of an apparatus 10 1900 for expanding a tubular member will be described. The apparatus 1900 preferably includes a drillpipe 1905, an innerstring adapter 1910, a sealing sleeve 1915, an inner sealing mandrel 1920, an upper sealing head 1925, a lower sealing head 1930, an outer sealing mandrel 1935, a load mandrel 1940, an expansion cone 1945, a mandrel launcher 1950, a mechanical slip body 1955, mechanical slips 1960, 15 drag blocks 1965, casing 1970, and fluid passages 1975, 1980, 1985, and 1990.

The drillpipe 1905 is coupled to the innerstring adapter 1910. During operation of the apparatus 1900, the drillpipe 1905 supports the apparatus 1900. The drillpipe 1905 preferably comprises a substantially hollow tubular member or members. The drillpipe 1905 may be fabricated from any number of conventional 20 commercially available materials such as, for example, oilfield country tubular drillpipe, fiberglass or coiled tubing. In a preferred embodiment, the drillpipe 1905 is fabricated from coiled tubing in order to facilitate the placement of the apparatus 1900 in non-vertical wellbores. The drillpipe 1905 may be coupled to the innerstring adapter 1910 using any number of conventional commercially available mechanical 25 couplings such as, for example, drillpipe connectors, OCTG specialty type box and pin connectors, a ratchet-latch type connector or a standard box by pin connector. In a preferred embodiment, the drillpipe 1905 is removably coupled to the innerstring adapter 1910 by a drillpipe connection.

5 The drillpipe 1905 preferably includes a fluid passage 1975 that is adapted to convey fluidic materials from a surface location into the fluid passage 1980. In a preferred embodiment, the fluid passage 1975 is adapted to convey fluidic materials such as, for example, cement, drilling mud, epoxy or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

10 The innerstring adapter 1910 is coupled to the drill string 1905 and the sealing sleeve 1915. The innerstring adapter 1910 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 1910 may be fabricated from any number of conventional commercially available materials such as, for example, oil country tubular goods, low alloy steel, carbon steel, stainless steel or other high strength materials. In a preferred embodiment, the innerstring adapter 1910 is fabricated from oilfield country tubular goods in order to optimally provide mechanical properties that closely match those of the drill string 1905.

15 The innerstring adapter 1910 may be coupled to the drill string 1905 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connectors, oilfield country tubular goods specialty type threaded connectors, ratchet-latch type stab in connector, or a standard threaded connection. In a preferred embodiment, the innerstring adapter 1910 is removably coupled to the drill pipe 1905 by a drillpipe connection. The innerstring adapter 1910 may be coupled to the sealing sleeve 1915 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connector, ratchet-latch type stab in connectors, or a standard threaded connection. In a preferred embodiment, the innerstring adapter 1910 is removably coupled to the sealing sleeve 1915 by a standard threaded connection.

25 The innerstring adapter 1910 preferably includes a fluid passage 1980 that is adapted to convey fluidic materials from the fluid passage 1975 into the fluid passage 1985. In a preferred embodiment, the fluid passage 1980 is adapted to convey fluidic materials such as, for example, cement, drilling mud, epoxy, or lubricants at

operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

5 The sealing sleeve 1915 is coupled to the innerstring adapter 1910 and the inner sealing mandrel 1920. The sealing sleeve 1915 preferably comprises a substantially hollow tubular member or members. The sealing sleeve 1915 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, carbon steel, low alloy steel, stainless steel or other high strength materials. In a preferred embodiment, the sealing sleeve 1915 is fabricated from oilfield country tubular goods in order to optimally provide mechanical properties that substantially match the remaining components of the apparatus 1900.

10 The sealing sleeve 1915 may be coupled to the innerstring adapter 1910 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type stab in connection, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 1915 is removably coupled to the innerstring adapter 1910 by a standard threaded connection. The sealing sleeve 1915 may be coupled to the inner sealing mandrel 1920 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 1915 is removably coupled to the inner sealing mandrel 1920 by a standard threaded connection.

20 The sealing sleeve 1915 preferably includes a fluid passage 1985 that is adapted to convey fluidic materials from the fluid passage 1980 into the fluid passage 1990. In a preferred embodiment, the fluid passage 1985 is adapted to convey fluidic materials such as, for example, cement, drilling mud, epoxy or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The inner sealing mandrel 1920 is coupled to the sealing sleeve 1915 and the lower sealing head 1930. The inner sealing mandrel 1920 preferably comprises a substantially hollow tubular member or members. The inner sealing mandrel 1920 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, low alloy steel, carbon steel or other similar high strength materials. In a preferred embodiment, the inner sealing mandrel 1920 is fabricated from stainless steel in order to optimally provide mechanical properties similar to the other components of the apparatus 1900 while also providing a smooth outer surface to support seals and other moving parts that can operate with minimal wear, corrosion and pitting.

The inner sealing mandrel 1920 may be coupled to the sealing sleeve 1915 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 1920 is removably coupled to the sealing sleeve 1915 by a standard threaded connections. The inner sealing mandrel 1920 may be coupled to the lower sealing head 1930 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type stab in connectors or standard threaded connections. In a preferred embodiment, the inner sealing mandrel 1920 is removably coupled to the lower sealing head 1930 by a standard threaded connections connection.

The inner sealing mandrel 1920 preferably includes a fluid passage 1990 that is adapted to convey fluidic materials from the fluid passage 1985 into the fluid passage 1995. In a preferred embodiment, the fluid passage 1990 is adapted to convey fluidic materials such as, for example, cement, drilling mud, epoxy or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

5 The upper sealing head 1925 is coupled to the outer sealing mandrel 1935 and the expansion cone 1945. The upper sealing head 1925 is also movably coupled to the outer surface of the inner sealing mandrel 1920 and the inner surface of the casing 1970. In this manner, the upper sealing head 1925, outer sealing mandrel 1935, and the expansion cone 1945 reciprocate in the axial direction. The radial clearance between the inner cylindrical surface of the upper sealing head 1925 and the outer surface of the inner sealing mandrel 1920 may range, for example, from about 0.025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the upper sealing head 1925 and the outer surface of the inner sealing mandrel 1920 ranges from about 0.005 to 0.01 inches in order to optimally provide clearance for pressure seal placement. The radial clearance between the outer cylindrical surface of the upper sealing head 1925 and the inner surface of the casing 1970 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the upper sealing head 1925 and the inner surface of the casing 1970 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 1945 as the expansion cone 1945 is upwardly moved inside the casing 1970.

20 The upper sealing head 1925 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The upper sealing head 1925 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, machine tool steel, or similar high strength materials. In a preferred embodiment, the upper sealing head 1925 is fabricated from stainless steel in order to optimally provide high strength and smooth outer surfaces that are resistant to wear, galling, corrosion and pitting.

25 The inner surface of the upper sealing head 1925 preferably includes one or more annular sealing members 2000 for sealing the interface between the upper sealing head 1925 and the inner sealing mandrel 1920. The sealing members 2000 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals.

In a preferred embodiment, the sealing members 2000 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial motion.

5 In a preferred embodiment, the upper sealing head 1925 includes a shoulder 2005 for supporting the upper sealing head 1925 on the lower sealing head 1930.

The upper sealing head 1925 may be coupled to the outer sealing mandrel 1935 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connections. In a preferred
10 embodiment, the upper sealing head 1925 is removably coupled to the outer sealing mandrel 1935 by a standard threaded connections. In a preferred embodiment, the mechanical coupling between the upper sealing head 1925 and the outer sealing mandrel 1935 includes one or more sealing members 2010 for fluidically sealing the interface between the upper sealing head 1925 and the outer sealing mandrel 1935.
15 The sealing members 2010 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2010 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroking motion.

20 The lower sealing head 1930 is coupled to the inner sealing mandrel 1920 and the load mandrel 1940. The lower sealing head 1930 is also movably coupled to the inner surface of the outer sealing mandrel 1935. In this manner, the upper sealing head 1925 and outer sealing mandrel 1935 reciprocate in the axial direction. The radial clearance between the outer surface of the lower sealing head 1930 and the
25 inner surface of the outer sealing mandrel 1935 may range, for example, from about 0.025 to 0.05 inches. In a preferred embodiment, the radial clearance between the outer surface of the lower sealing head 1930 and the inner surface of the outer sealing mandrel 1935 ranges from about 0.005 to 0.010 inches in order to optimally provide a close tolerance having room for the installation of pressure seal rings.

The lower sealing head 1930 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The lower sealing head 1930 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, stainless steel, machine tool steel or other similar high strength materials. In a preferred embodiment, the lower sealing head 1930 is fabricated from stainless steel in order to optimally provide high strength and resistance to wear, galling, corrosion, and pitting.

The outer surface of the lower sealing head 1930 preferably includes one or more annular sealing members 2015 for sealing the interface between the lower sealing head 1930 and the outer sealing mandrel 1935. The sealing members 2015 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2015 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head 1930 may be coupled to the inner sealing mandrel 1920 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the lower sealing head 1930 is removably coupled to the inner sealing mandrel 1920 by a standard threaded connection.

In a preferred embodiment, the mechanical coupling between the lower sealing head 1930 and the inner sealing mandrel 1920 includes one or more sealing members 2020 for fluidically sealing the interface between the lower sealing head 1930 and the inner sealing mandrel 1920. The sealing members 2020 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2020 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial motion.

The lower sealing head 1930 may be coupled to the load mandrel 1940 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connections, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the lower sealing head 1930 is removably coupled to the load mandrel 1940 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 1930 and the load mandrel 1940 includes one or more sealing members 2025 for fluidically sealing the interface between the lower sealing head 1930 and the load mandrel 1940. The sealing members 2025 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2025 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the lower sealing head 1930 includes a throat passage 2040 fluidically coupled between the fluid passages 1990 and 1995. The throat passage 2040 is preferably of reduced size and is adapted to receive and engage with a plug 2045, or other similar device. In this manner, the fluid passage 1990 is fluidically isolated from the fluid passage 1995. In this manner, the pressure chamber 2030 is pressurized.

The outer sealing mandrel 1935 is coupled to the upper sealing head 1925 and the expansion cone 1945. The outer sealing mandrel 1935 is also movably coupled to the inner surface of the casing 1970 and the outer surface of the lower sealing head 1930. In this manner, the upper sealing head 1925, outer sealing mandrel 1935, and the expansion cone 1945 reciprocate in the axial direction. The radial clearance between the outer surface of the outer sealing mandrel 1935 and the inner surface of the casing 1970 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer surface of the outer sealing mandrel 1935 and the inner surface of the casing 1970 ranges from about 0.025 to 0.125 inches in order to optimally provide maximum piston surface area to

maximize the radial expansion force. The radial clearance between the inner surface of the outer sealing mandrel 1935 and the outer surface of the lower sealing head 1930 may range, for example, from about 0.025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner surface of the outer sealing
5 mandrel 1935 and the outer surface of the lower sealing head 1930 ranges from about 0.005 to 0.010 inches in order to optimally provide a minimum gap for the sealing elements to bridge and seal.

The outer sealing mandrel 1935 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The outer sealing mandrel
10 1935 may be fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, 13 chromium steel or stainless steel. In a preferred embodiment, the outer sealing mandrel 1935 is fabricated from stainless steel in order to optimally provide maximum strength and minimum wall thickness while also providing resistance to corrosion, galling and
15 pitting.

The outer sealing mandrel 1935 may be coupled to the upper sealing head 1925 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, standard threaded connections, or welding. In a preferred
20 embodiment, the outer sealing mandrel 1935 is removably coupled to the upper sealing head 1925 by a standard threaded connections connection. The outer sealing mandrel 1935 may be coupled to the expansion cone 1945 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded
25 connection, or a standard threaded connections connection, or welding. In a preferred embodiment, the outer sealing mandrel 1935 is removably coupled to the expansion cone 1945 by a standard threaded connections connection.

The upper sealing head 1925, the lower sealing head 1930, the inner sealing mandrel 1920, and the outer sealing mandrel 1935 together define a pressure

chamber 2030. The pressure chamber 2030 is fluidically coupled to the passage 1990 via one or more passages 2035. During operation of the apparatus 1900, the plug 2045 engages with the throat passage 2040 to fluidically isolate the fluid passage 1990 from the fluid passage 1995. The pressure chamber 2030 is then pressurized which
5 in turn causes the upper sealing head 1925, outer sealing mandrel 1935, and expansion cone 1945 to reciprocate in the axial direction. The axial motion of the expansion cone 1945 in turn expands the casing 1970 in the radial direction.

The load mandrel 1940 is coupled to the lower sealing head 1930 and the mechanical slip body 1955. The load mandrel 1940 preferably comprises an annular
10 member having substantially cylindrical inner and outer surfaces. The load mandrel 1940 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the load mandrel 1940 is fabricated from oilfield country tubular goods
15 in order to optimally provide high strength.

The load mandrel 1940 may be coupled to the lower sealing head 1930 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In a
20 preferred embodiment, the load mandrel 1940 is removably coupled to the lower sealing head 1930 by a standard threaded connection. The load mandrel 1940 may be coupled to the mechanical slip body 1955 using any number of conventional commercially available mechanical couplings such as, for example, a drillpipe connection, oilfield country tubular goods specialty type threaded connections,
25 welding, amorphous bonding, or a standard threaded connections connection. In a preferred embodiment, the load mandrel 1940 is removably coupled to the mechanical slip body 1955 by a standard threaded connections connection.

The load mandrel 1940 preferably includes a fluid passage 1995 that is adapted to convey fluidic materials from the fluid passage 1990 to the region outside of the

apparatus 1900. In a preferred embodiment, the fluid passage 1995 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

5 The expansion cone 1945 is coupled to the outer sealing mandrel 1935. The expansion cone 1945 is also movably coupled to the inner surface of the casing 1970. In this manner, the upper sealing head 1925, outer sealing mandrel 1935, and the expansion cone 1945 reciprocate in the axial direction. The reciprocation of the expansion cone 1945 causes the casing 1970 to expand in the radial direction.

10 The expansion cone 1945 preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In a preferred embodiment, the outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide cone dimensions for the typical
15 range of tubular members.

 The axial length of the expansion cone 1945 may range, for example, from about 2 to 8 times the largest outer diameter of the expansion cone 1945. In a preferred embodiment, the axial length of the expansion cone 1945 ranges from about 3 to 5 times the largest outer diameter of the expansion cone 1945 in order to
20 optimally provide stability and centralization of the expansion cone 1945 during the expansion process. In a preferred embodiment, the angle of attack of the expansion cone 1945 ranges from about 5 to 30 degrees in order to optimally balance friction forces with the desired amount of radial expansion. The expansion cone 1945 angle of attack will vary as a function of the operating parameters of the particular
25 expansion operation.

 The expansion cone 1945 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, ceramics, tungsten carbide, nitride steel, or other similar high strength materials. In a preferred embodiment, the expansion cone 1945 is fabricated from D2 machine tool

steel in order to optimally provide high strength and resistance to corrosion, wear, galling, and pitting. In a particularly preferred embodiment, the outside surface of the expansion cone 1945 has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength and resist wear and galling.

5 The expansion cone 1945 may be coupled to the outside sealing mandrel 1935 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield tubular country goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connections connection. In a preferred embodiment, the expansion cone 1945 is
10 coupled to the outside sealing mandrel 1935 using a standard threaded connections connection in order to optimally provide connector strength for the typical operating loading conditions while also permitting easy replacement of the expansion cone 1945.

 The mandrel launcher 1950 is coupled to the casing 1970. The mandrel
15 launcher 1950 comprises a tubular section of casing having a reduced wall thickness compared to the casing 1970. In a preferred embodiment, the wall thickness of the mandrel launcher is about 50 to 100 % of the wall thickness of the casing 1970. In this manner, the initiation of the radial expansion of the casing 1970 is facilitated, and the insertion of the larger outside diameter mandrel launcher 1950 into the
20 wellbore and/or casing is facilitated.

 The mandrel launcher 1950 may be coupled to the casing 1970 using any number of conventional mechanical couplings. The mandrel launcher 1950 may have a wall thickness ranging, for example, from about 0.15 to 1.5 inches. In a preferred
25 embodiment, the wall thickness of the mandrel launcher 1950 ranges from about 0.25 to 0.75 inches in order to optimally provide high strength with a small overall profile. The mandrel launcher 1950 may be fabricated from any number of conventional commercially available materials such as, for example, oil field tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the mandrel launcher 1950 is fabricated from oil field

tubular goods of higher strength but lower wall thickness than the casing 1970 in order to optimally provide a thin walled container with approximately the same burst strength as the casing 1970.

5 The mechanical slip body 1955 is coupled to the load mandrel 1970, the mechanical slips 1960, and the drag blocks 1965. The mechanical slip body 1955 preferably comprises a tubular member having an inner passage 2050 fluidically coupled to the passage 1995. In this manner, fluidic materials may be conveyed from the passage 2050 to a region outside of the apparatus 1900.

10 The mechanical slip body 1955 may be coupled to the load mandrel 1940 using any number of conventional mechanical couplings. In a preferred embodiment, the mechanical slip body 1955 is removably coupled to the load mandrel 1940 using a standard threaded connection in order to optimally provide high strength and permit the mechanical slip body 1955 to be easily replaced. The mechanical slip body 1955 may be coupled to the mechanical slips 1955 using any number of conventional
15 mechanical couplings. In a preferred embodiment, the mechanical slip body 1955 is removably coupled to the mechanical slips 1955 using threads and sliding steel retainer rings in order to optimally provide high strength coupling and also permit easy replacement of the mechanical slips 1955. The mechanical slip body 1955 may be coupled to the drag blocks 1965 using any number of conventional mechanical
20 couplings. In a preferred embodiment, the mechanical slip body 1955 is removably coupled to the drag blocks 1965 using threaded connections and sliding steel retainer rings in order to optimally provide high strength and also permit easy replacement of the drag blocks 1965.

25 The mechanical slips 1960 are coupled to the outside surface of the mechanical slip body 1955. During operation of the apparatus 1900, the mechanical slips 1960 prevent upward movement of the casing 1970 and mandrel launcher 1950. In this manner, during the axial reciprocation of the expansion cone 1945, the casing 1970 and mandrel launcher 1950 are maintained in a substantially stationary position. In

this manner, the mandrel launcher 1950 and casing 1970 are expanded in the radial direction by the axial movement of the expansion cone 1945.

The mechanical slips 1960 may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In a preferred embodiment, the mechanical slips 1960 comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 1970 during the expansion process.

The drag blocks 1965 are coupled to the outside surface of the mechanical slip body 1955. During operation of the apparatus 1900, the drag blocks 1965 prevent upward movement of the casing 1970 and mandrel launcher 1950. In this manner, during the axial reciprocation of the expansion cone 1945, the casing 1970 and mandrel launcher 1950 are maintained in a substantially stationary position. In this manner, the mandrel launcher 1950 and casing 1970 are expanded in the radial direction by the axial movement of the expansion cone 1945.

The drag blocks 1965 may comprise any number of conventional commercially available mechanical slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. In a preferred embodiment, the drag blocks 1965 comprise RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 1970 during the expansion process.

The casing 1970 is coupled to the mandrel launcher 1950. The casing 1970 is further removably coupled to the mechanical slips 1960 and drag blocks 1965. The casing 1970 preferably comprises a tubular member. The casing 1970 may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oil field country tubular goods, low alloy steel,

carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the casing 1970 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength. In a preferred embodiment, the upper end of the casing 1970 includes
5 one or more sealing members positioned about the exterior of the casing 1970.

During operation, the apparatus 1900 is positioned in a wellbore with the upper end of the casing 1970 positioned in an overlapping relationship within an existing wellbore casing. In order minimize surge pressures within the borehole during placement of the apparatus 1900, the fluid passage 1975 is preferably provided
10 with one or more pressure relief passages. During the placement of the apparatus 1900 in the wellbore, the casing 1970 is supported by the expansion cone 1945.

After positioning of the apparatus 1900 within the bore hole in an overlapping relationship with an existing section of wellbore casing, a first fluidic material is pumped into the fluid passage 1975 from a surface location. The first fluidic material
15 is conveyed from the fluid passage 1975 to the fluid passages 1980, 1985, 1990, 1995, and 2050. The first fluidic material will then exit the apparatus and fill the annular region between the outside of the apparatus 1900 and the interior walls of the bore hole.

The first fluidic material may comprise any number of conventional commercially available materials such as, for example, drilling mud, water, epoxy or cement. In a preferred embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, cement or epoxy. In this manner, a wellbore casing having an outer annular layer of a hardenable material may be
20 formed.

The first fluidic material may be pumped into the apparatus 1900 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi, and 0 to 3,000 gallons/minute. In a preferred embodiment, the first fluidic material is pumped
25 into the apparatus 1900 at operating pressures and flow rates ranging from about 0

to 4,500 psi and 0 to 3,000 gallons/minute in order to optimally provide operating pressures and flow rates for typical operating conditions.

At a predetermined point in the injection of the first fluidic material such as, for example, after the annular region outside of the apparatus 1900 has been filled to a predetermined level, a plug 2045, dart, or other similar device is introduced into the first fluidic material. The plug 2045 lodges in the throat passage 2040 thereby fluidically isolating the fluid passage 1990 from the fluid passage 1995.

After placement of the plug 2045 in the throat passage 2040, a second fluidic material is pumped into the fluid passage 1975 in order to pressurize the pressure chamber 2030. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricant. In a preferred embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud or lubricant in order minimize frictional forces.

The second fluidic material may be pumped into the apparatus 1900 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the second fluidic material is pumped into the apparatus 1900 at operating pressures and flow rates ranging from about 0 to 3,500 psi, and 0 to 1,200 gallons/minute in order to optimally provide expansion of the casing 1970.

The pressurization of the pressure chamber 2030 causes the upper sealing head 1925, outer sealing mandrel 1935, and expansion cone 1945 to move in an axial direction. As the expansion cone 1945 moves in the axial direction, the expansion cone 1945 pulls the mandrel launcher 1950 and drag blocks 1965 along, which sets the mechanical slips 1960 and stops further axial movement of the mandrel launcher 1950 and casing 1970. In this manner, the axial movement of the expansion cone 1945 radially expands the mandrel launcher 1950 and casing 1970.

Once the upper sealing head 1925, outer sealing mandrel 1935, and expansion cone 1945 complete an axial stroke, the operating pressure of the second fluidic

material is reduced and the drill string 1905 is raised. This causes the inner sealing mandrel 1920, lower sealing head 1930, load mandrel 1940, and mechanical slip body 1955 to move upward. This unsets the mechanical slips 1960 and permits the mechanical slips 1960 and drag blocks 1965 to be moved upward within the mandrel launcher and casing 1970. When the lower sealing head 1930 contacts the upper sealing head 1925, the second fluidic material is again pressurized and the radial expansion process continues. In this manner, the mandrel launcher 1950 and casing 1970 are radial expanded through repeated axial strokes of the upper sealing head 1925, outer sealing mandrel 1935 and expansion cone 1945. Throughput the radial expansion process, the upper end of the casing 1970 is preferably maintained in an overlapping relation with an existing section of wellbore casing.

At the end of the radial expansion process, the upper end of the casing 1970 is expanded into intimate contact with the inside surface of the lower end of the existing wellbore casing. In a preferred embodiment, the sealing members provided at the upper end of the casing 1970 provide a fluidic seal between the outside surface of the upper end of the casing 1970 and the inside surface of the lower end of the existing wellbore casing. In a preferred embodiment, the contact pressure between the casing 1970 and the existing section of wellbore casing ranges from about 400 to 10,000 psi in order to optimally provide contact pressure for activating sealing members, provide optimal resistance to axial movement of the expanded casing 1970, and optimally support typical tensile and compressive loads.

In a preferred embodiment, as the expansion cone 1945 nears the end of the casing 1970, the operating flow rate of the second fluidic material is reduced in order to minimize shock to the apparatus 1900. In an alternative embodiment, the apparatus 1900 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 1970.

In a preferred embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 1945 nears the end of the casing 1970 in order to optimally provide reduced axial movement and

velocity of the expansion cone 1945. In a preferred embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 1900 to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone 1945. In a preferred embodiment, the stroke
5 length of the apparatus 1900 ranges from about 10 to 45 feet in order to optimally provide equipment lengths that can be handled by typical oil well rigging equipment while also minimizing the frequency at which the expansion cone 1945 must be stopped so the apparatus 1900 can be re-stroked for further expansion operations.

In an alternative embodiment, at least a portion of the upper sealing head 1925
10 includes an expansion cone for radially expanding the mandrel launcher 1950 and casing 1970 during operation of the apparatus 1900 in order to increase the surface area of the casing 1970 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

In an alternative embodiment, mechanical slips are positioned in an axial
15 location between the sealing sleeve 1915 and the inner sealing mandrel 1920 in order to simplify the operation and assembly of the apparatus 1900.

Upon the complete radial expansion of the casing 1970, if applicable, the first fluidic material is permitted to cure within the annular region between the outside of the expanded casing 1970 and the interior walls of the wellbore. In the case where
20 the expanded casing 1970 is slotted, the cured fluidic material will preferably permeate and envelop the expanded casing. In this manner, a new section of wellbore casing is formed within a wellbore. Alternatively, the apparatus 1900 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 1900 may be used to directly line the interior of a wellbore with a casing,
25 without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 1900 may be used to expand a tubular support member in a hole.

During the radial expansion process, the pressurized areas of the apparatus 1900 are limited to the fluid passages 1975, 1980, 1985, and 1990, and the pressure chamber 2030. No fluid pressure acts directly on the mandrel launcher 1950 and

casing 1970. This permits the use of operating pressures higher than the mandrel launcher 1950 and casing 1970 could normally withstand.

Referring now to Figure 16, a preferred embodiment of an apparatus 2100 for forming a mono-diameter wellbore casing will be described. The apparatus 2100 preferably includes a drillpipe 2105, an innerstring adapter 2110, a sealing sleeve 2115, an inner sealing mandrel 2120, slips 2125, upper sealing head 2130, lower sealing head 2135, outer sealing mandrel 2140, load mandrel 2145, expansion cone 2150, and casing 2155.

10 The drillpipe 2105 is coupled to the innerstring adapter 2110. During operation of the apparatus 2100, the drillpipe 2105 supports the apparatus 2100. The drillpipe 2105 preferably comprises a substantially hollow tubular member or members. The drillpipe 2105 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength material.

15 In a preferred embodiment, the drillpipe 2105 is fabricated from coiled tubing in order to facilitate the placement of the apparatus 1900 in non-vertical wellbores. The drillpipe 2105 may be coupled to the innerstring adapter 2110 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded

20 connection, ratchet-latch type connection, or a standard threaded connection. In a preferred embodiment, the drillpipe 2105 is removably coupled to the innerstring adapter 2110 by a drill pipe connection.

25 The drillpipe 2105 preferably includes a fluid passage 2160 that is adapted to convey fluidic materials from a surface location into the fluid passage 2165. In a preferred embodiment, the fluid passage 2160 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The innerstring adapter 2110 is coupled to the drill string 2105 and the sealing sleeve 2115. The innerstring adapter 2110 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 2110 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In a preferred embodiment, the innerstring adapter 2110 is fabricated from stainless steel in order to optimally provide high strength, low friction, and resistance to corrosion and wear.

The innerstring adapter 2110 may be coupled to the drill string 2105 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection or a standard threaded connection. In a preferred embodiment, the innerstring adapter 2110 is removably coupled to the drill pipe 2105 by a drillpipe connection. The innerstring adapter 2110 may be coupled to the sealing sleeve 2115 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. In a preferred embodiment, the innerstring adapter 2110 is removably coupled to the sealing sleeve 2115 by a standard threaded connection.

The innerstring adapter 2110 preferably includes a fluid passage 2165 that is adapted to convey fluidic materials from the fluid passage 2160 into the fluid passage 2170. In a preferred embodiment, the fluid passage 2165 is adapted to convey fluidic materials such as, for example, cement, epoxy, water drilling muds, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve 2115 is coupled to the innerstring adapter 2110 and the inner sealing mandrel 2120. The sealing sleeve 2115 preferably comprises a substantially hollow tubular member or members. The sealing sleeve 2115 may be

fabricated from any number of conventional commercially available materials such as, for example, oil field tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the sealing sleeve 2115 is fabricated from stainless steel in order to optimally provide high strength, low friction surfaces, and resistance to corrosion, wear, galling, and pitting.

The sealing sleeve 2115 may be coupled to the innerstring adapter 2110 using any number of conventional commercially available mechanical couplings such as, for example, a standard threaded connection, oilfield country tubular goods specialty type threaded connections, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 2115 is removably coupled to the innerstring adapter 2110 by a standard threaded connection. The sealing sleeve 2115 may be coupled to the inner sealing mandrel 2120 using any number of conventional commercially available mechanical couplings such as, for example, a standard threaded connection, oilfield country tubular goods specialty type threaded connections, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the sealing sleeve 2115 is removably coupled to the inner sealing mandrel 2120 by a standard threaded connection.

The sealing sleeve 2115 preferably includes a fluid passage 2170 that is adapted to convey fluidic materials from the fluid passage 2165 into the fluid passage 2175. In a preferred embodiment, the fluid passage 2170 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The inner sealing mandrel 2120 is coupled to the sealing sleeve 2115, slips 2125, and the lower sealing head 2135. The inner sealing mandrel 2120 preferably comprises a substantially hollow tubular member or members. The inner sealing mandrel 2120 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a

preferred embodiment, the inner sealing mandrel 2120 is fabricated from stainless steel in order to optimally provide high strength, low friction surfaces, and corrosion and wear resistance.

5 The inner sealing mandrel 2120 may be coupled to the sealing sleeve 2115 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 2120 is removably coupled to the sealing sleeve 2115 by a standard threaded connection. The standard threaded connection provides high
10 strength and permits easy replacement of components. The inner sealing mandrel 2120 may be coupled to the slips 2125 using any number of conventional commercially available mechanical couplings such as, for example, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel 2120 is removably coupled to the slips 2125 by a standard
15 threaded connection. The inner sealing mandrel 2120 may be coupled to the lower sealing head 2135 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the inner sealing mandrel
20 2120 is removably coupled to the lower sealing head 2135 by a standard threaded connection.

The inner sealing mandrel 2120 preferably includes a fluid passage 2175 that is adapted to convey fluidic materials from the fluid passage 2170 into the fluid passage 2180. In a preferred embodiment, the fluid passage 2175 is adapted to convey
25 fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The slips 2125 are coupled to the outer surface of the inner sealing mandrel 2120. During operation of the apparatus 2100, the slips 2125 preferably maintain the

casing 2155 in a substantially stationary position during the radial expansion of the casing 2155. In a preferred embodiment, the slips 2125 are activated using the fluid passages 2185 to convey pressurized fluid material into the slips 2125.

5 The slips 2125 may comprise any number of commercially available hydraulic slips such as, for example, RTTS packer tungsten carbide hydraulic slips or Model 3L retrievable bridge plug hydraulic slips. In a preferred embodiment, the slips 2125 comprise RTTS packer tungsten carbide hydraulic slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 2155 during the expansion process. In a particularly preferred embodiment,
10 the slips include a fluid passage 2190, pressure chamber 2195, spring return 2200, and slip member 2205.

The slips 2125 may be coupled to the inner sealing mandrel 2120 using any number of conventional mechanical couplings. In a preferred embodiment, the slips 2125 are removably coupled to the outer surface of the inner sealing mandrel 2120
15 by a thread connection in order to optimally provide interchangeability of parts.

The upper sealing head 2130 is coupled to the outer sealing mandrel 2140 and expansion cone 2150. The upper sealing head 2130 is also movably coupled to the outer surface of the inner sealing mandrel 2120 and the inner surface of the casing 2155. In this manner, the upper sealing head 2130 reciprocates in the axial direction.
20 The radial clearance between the inner cylindrical surface of the upper sealing head 2130 and the outer surface of the inner sealing mandrel 2120 may range, for example, from about 0.025 to 0.05 inches. In a preferred embodiment, the radial clearance between the inner cylindrical surface of the upper sealing head 2130 and the outer surface of the inner sealing mandrel 2120 ranges from about 0.005 to 0.010 inches in
25 order to optimally provide a pressure seal. The radial clearance between the outer cylindrical surface of the upper sealing head 2130 and the inner surface of the casing 2155 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer cylindrical surface of the upper sealing head 2130 and the inner surface of the casing 2155 ranges from about 0.025

to 0.125 inches in order to optimally provide stabilization for the expansion cone 2130 during axial movement of the expansion cone 2130.

5 The upper sealing head 2130 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The upper sealing head 2130 may be fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the upper sealing head 2130 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the upper sealing head 10 2130 preferably includes one or more annular sealing members 2210 for sealing the interface between the upper sealing head 2130 and the inner sealing mandrel 2120. The sealing members 2210 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2210 15 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the upper sealing head 2130 includes a shoulder 2215 for supporting the upper sealing head 2130 on the lower sealing head 2135.

20 The upper sealing head 2130 may be coupled to the outer sealing mandrel 2140 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the upper sealing head 2130 is removably coupled to the outer sealing mandrel 2140 by a standard threaded connection. In a preferred 25 embodiment, the mechanical coupling between the upper sealing head 2130 and the outer sealing mandrel 2140 includes one or more sealing members 2220 for fluidically sealing the interface between the upper sealing head 2130 and the outer sealing mandrel 2140. The sealing members 2220 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals,

or metal spring energized seals. In a preferred embodiment, the sealing members 2220 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

5 The lower sealing head 2135 is coupled to the inner sealing mandrel 2120 and the load mandrel 2145. The lower sealing head 2135 is also movably coupled to the inner surface of the outer sealing mandrel 2140. In this manner, the upper sealing head 2130, outer sealing mandrel 2140, and expansion cone 2150 reciprocate in the axial direction. The radial clearance between the outer surface of the lower sealing head 2135 and the inner surface of the outer sealing mandrel 2140 may range, for
10 example, from about 0.0025 to 0.05 inches. In a preferred embodiment, the radial clearance between the outer surface of the lower sealing head 2135 and the inner surface of the outer sealing mandrel 2140 ranges from about 0.0025 to 0.05 inches in order to optimally provide minimal radial clearance.

The lower sealing head 2135 preferably comprises an annular member having
15 substantially cylindrical inner and outer surfaces. The lower sealing head 2135 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the lower sealing head 2135 is fabricated from stainless steel in order to optimally provide high
20 strength, corrosion resistance, and low friction surfaces. The outer surface of the lower sealing head 2135 preferably includes one or more annular sealing members 2225 for sealing the interface between the lower sealing head 2135 and the outer sealing mandrel 2140. The sealing members 2225 may comprise any number of conventional commercially available annular sealing members such as, for example,
25 o-rings, polypak seals or metal spring energized seals. In a preferred embodiment, the sealing members 2225 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head 2135 may be coupled to the inner sealing mandrel 2120 using any number of conventional commercially available mechanical couplings such

as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the lower sealing head 2135 is removably coupled to the inner sealing mandrel 2120 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 2135 and the inner sealing mandrel 2120 includes one or more sealing members 2230 for fluidically sealing the interface between the lower sealing head 2135 and the inner sealing mandrel 2120. The sealing members 2230 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2230 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The lower sealing head 2135 may be coupled to the load mandrel 2145 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the lower sealing head 2135 is removably coupled to the load mandrel 2145 by a standard threaded connection. In a preferred embodiment, the mechanical coupling between the lower sealing head 2135 and the load mandrel 2145 includes one or more sealing members 2235 for fluidically sealing the interface between the lower sealing head 2135 and the load mandrel 2145. The sealing members 2235 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. In a preferred embodiment, the sealing members 2235 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

In a preferred embodiment, the lower sealing head 2135 includes a throat passage 2240 fluidically coupled between the fluid passages 2175 and 2180. The throat passage 2240 is preferably of reduced size and is adapted to receive and engage with a plug 2245, or other similar device. In this manner, the fluid passage 2175 is

fluidically isolated from the fluid passage 2180. In this manner, the pressure chamber 2250 is pressurized.

5 The outer sealing mandrel 2140 is coupled to the upper sealing head 2130 and the expansion cone 2150. The outer sealing mandrel 2140 is also movably coupled to the inner surface of the casing 2155 and the outer surface of the lower sealing head 2135. In this manner, the upper sealing head 2130, outer sealing mandrel 2140, and the expansion cone 2150 reciprocate in the axial direction. The radial clearance between the outer surface of the outer sealing mandrel 2140 and the inner surface of the casing 2155 may range, for example, from about 0.025 to 0.375 inches. In a preferred embodiment, the radial clearance between the outer surface of the outer sealing mandrel 2140 and the inner surface of the casing 2155 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 2130 during the expansion process. The radial clearance between the inner surface of the outer sealing mandrel 2140 and the outer surface of the lower sealing head 2135 may range, for example, from about 0.005 to 0.125 inches. In a preferred embodiment, the radial clearance between the inner surface of the outer sealing mandrel 2140 and the outer surface of the lower sealing head 2135 ranges from about 0.005 to 0.010 inches in order to optimally provide minimal radial clearance.

20 The outer sealing mandrel 2140 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The outer sealing mandrel 2140 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. In a preferred embodiment, the outer sealing mandrel 2140 is fabricated from stainless steel in order to optionally provide high strength, corrosion resistance, and low friction surfaces.

The outer sealing mandrel 2140 may be coupled to the upper sealing head 2130 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded

connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the outer sealing mandrel 2140 is removably coupled to the upper sealing head 2130 by a standard threaded connection. The outer sealing mandrel 2140 may be coupled to the expansion cone 2150 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, welding, amorphous bonding, or a standard threaded connection. In a preferred embodiment, the outer sealing mandrel 2140 is removably coupled to the expansion cone 2150 by a standard threaded connection.

The upper sealing head 2130, the lower sealing head 2135, inner sealing mandrel 2120, and the outer sealing mandrel 2140 together define a pressure chamber 2250. The pressure chamber 2250 is fluidically coupled to the passage 2175 via one or more passages 2255. During operation of the apparatus 2100, the plug 2245 engages with the throat passage 2240 to fluidically isolate the fluid passage 2175 from the fluid passage 2180. The pressure chamber 2250 is then pressurized which in turn causes the upper sealing head 2130, outer sealing mandrel 2140, and expansion cone 2150 to reciprocate in the axial direction. The axial motion of the expansion cone 2150 in turn expands the casing 2155 in the radial direction.

The load mandrel 2145 is coupled to the lower sealing head 2135. The load mandrel 2145 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel 2145 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the load mandrel 2145 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction bearing surfaces.

The load mandrel 2145 may be coupled to the lower sealing head 2135 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded

connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the load mandrel 2145 is removably coupled to the lower sealing head 2135 by a standard threaded connection in order to optimally provide high strength and permit easy replacement of the load mandrel 2145.

5 The load mandrel 2145 preferably includes a fluid passage 2180 that is adapted to convey fluidic materials from the fluid passage 2180 to the region outside of the apparatus 2100. In a preferred embodiment, the fluid passage 2180 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi
10 and 0 to 3,000 gallons/minute.

 The expansion cone 2150 is coupled to the outer sealing mandrel 2140. The expansion cone 2150 is also movably coupled to the inner surface of the casing 2155. In this manner, the upper sealing head 2130, outer sealing mandrel 2140, and the expansion cone 2150 reciprocate in the axial direction. The reciprocation of the
15 expansion cone 2150 causes the casing 2155 to expand in the radial direction.

 The expansion cone 2150 preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. In a preferred embodiment, the outside radius of the outside conical surface ranges from
20 about 3 to 28 inches in order to optimally provide cone dimensions that are optimal for typical casings. The axial length of the expansion cone 2150 may range, for example, from about 2 to 6 times the largest outside diameter of the expansion cone 2150. In a preferred embodiment, the axial length of the expansion cone 2150 ranges from about 3 to 5 times the largest outside diameter of the expansion cone 2150 in
25 order to optimally provide stability and centralization of the expansion cone 2150 during the expansion process. In a particularly preferred embodiment, the maximum outside diameter of the expansion cone 2150 is between about 90 to 100 % of the inside diameter of the existing wellbore that the casing 2155 will be joined with. In a preferred embodiment, the angle of attack of the expansion cone 2150 ranges from

about 5 to 30 degrees in order to optimally balance friction forces and radial expansion forces. The optimal expansion cone 2150 angle of attack will vary as a function of the particular operating conditions of the expansion operation.

5 The expansion cone 2150 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics, or other similar high strength materials. In a preferred embodiment, the expansion cone 2150 is fabricated from D2 machine tool steel in order to optimally provide high strength and resistance to wear and galling. In a particularly preferred embodiment, the outside surface of the expansion
10 cone 2150 has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide resistance to wear.

The expansion cone 2150 may be coupled to the outside sealing mandrel 2140 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type
15 threaded connection, welding, amorphous bonding or a standard threaded connection. In a preferred embodiment, the expansion cone 2150 is coupled to the outside sealing mandrel 2140 using a standard threaded connection in order to optimally provide high strength and permit the expansion cone 2150 to be easily replaced.

20 The casing 2155 is removably coupled to the slips 2125 and expansion cone 2150. The casing 2155 preferably comprises a tubular member. The casing 2155 may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength material. In a preferred
25 embodiment, the casing 2155 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength.

In a preferred embodiment, the upper end 2260 of the casing 2155 includes a thin wall section 2265 and an outer annular sealing member 2270. In a preferred

embodiment, the wall thickness of the thin wall section 2265 is about 50 to 100 % of the regular wall thickness of the casing 2155. In this manner, the upper end 2260 of the casing 2155 may be easily expanded and deformed into intimate contact with the lower end of an existing section of wellbore casing. In a preferred embodiment, the lower end of the existing section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section 2265 of casing 2155 into the thin walled section of the existing wellbore casing results in a wellbore casing having a substantially constant inside diameter.

The annular sealing member 2270 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In a preferred embodiment, the annular sealing member 2270 is fabricated from StrataLock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the annular sealing member 2270 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the wellbore casing that the casing 2155 is joined to. In this manner, after expansion, the annular sealing member 2270 preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside surface of the existing section of wellbore casing during the radial expansion of the casing 2155 to support the casing 2155.

In a preferred embodiment, the lower end 2275 of the casing 2155 includes a thin wall section 2280 and an outer annular sealing member 2285. In a preferred embodiment, the wall thickness of the thin wall section 2280 is about 50 to 100 % of the regular wall thickness of the casing 2155. In this manner, the lower end 2275 of the casing 2155 may be easily expanded and deformed. Furthermore, in this manner, an other section of casing may be easily joined with the lower end 2275 of the casing 2155 using a radial expansion process. In a preferred embodiment, the upper end of the other section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section of the upper end of the other casing into

the thin walled section 2280 of the lower end of the casing 2155 results in a wellbore casing having a substantially constant inside diameter.

5 The annular sealing member 2285 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. In a preferred embodiment, the annular sealing member 2285 is fabricated from StrataLock epoxy in order to optimally provide compressibility and wear resistance. The outside diameter of the annular sealing member 2285 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the existing wellbore casing that the casing 2155 is joined to. In this manner, the annular sealing member 2285 preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside wall of the wellbore during the radial expansion of the casing 2155 to support the casing 2155.

10 During operation, the apparatus 2100 is preferably positioned in a wellbore with the upper end 2260 of the casing 2155 positioned in an overlapping relationship with the lower end of an existing wellbore casing. In a particularly preferred embodiment, the thin wall section 2265 of the casing 2155 is positioned in opposing overlapping relation with the thin wall section and outer annular sealing member of the lower end of the existing section of wellbore casing. In this manner, the radial expansion of the casing 2155 will compress the thin wall sections and annular compressible members of the upper end 2260 of the casing 2155 and the lower end of the existing wellbore casing into intimate contact. During the positioning of the apparatus 2100 in the wellbore, the casing 2155 is supported by the expansion cone 2150.

20 After positioning of the apparatus 2100, a first fluidic material is then pumped into the fluid passage 2160. The first fluidic material may comprise any number of conventional commercially available materials such as, for example, drilling mud, water, epoxy, or cement. In a preferred embodiment, the first fluidic material comprises a hardenable fluidic sealing material such as, for example, cement or epoxy

in order to provide a hardenable outer annular body around the expanded casing 2155.

5 The first fluidic material may be pumped into the fluid passage 2160 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 3,000 gallons/minute. In a preferred embodiment, the first fluidic material is pumped into the fluid passage 2160 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

10 The first fluidic material pumped into the fluid passage 2160 passes through the fluid passages 2165, 2170, 2175, 2180 and then outside of the apparatus 2100. The first fluidic material then fills the annular region between the outside of the apparatus 2100 and the interior walls of the wellbore.

15 The plug 2245 is then introduced into the fluid passage 2160. The plug 2245 lodges in the throat passage 2240 and fluidically isolates and blocks off the fluid passage 2175. In a preferred embodiment, a couple of volumes of a non-hardenable fluidic material are then pumped into the fluid passage 2160 in order to remove any hardenable fluidic material contained within and to ensure that none of the fluid passages are blocked.

20 A second fluidic material is then pumped into the fluid passage 2160. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, drilling mud, water, drilling gases, or lubricants. In a preferred embodiment, the second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud or lubricant in order to optimally provide pressurization of the pressure chamber 2250 and minimize frictional forces.

25 The second fluidic material may be pumped into the fluid passage 2160 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. In a preferred embodiment, the second fluidic material is pumped into the fluid passage 2160 at operating pressures and flow rates

ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

5 The second fluidic material pumped into the fluid passage 2160 passes through the fluid passages 2165, 2170, and 2175 into the pressure chambers 2195 of the slips 2125, and into the pressure chamber 2250. Continued pumping of the second fluidic material pressurizes the pressure chambers 2195 and 2250.

The pressurization of the pressure chambers 2195 causes the slip members 2205 to expand in the radial direction and grip the interior surface of the casing 2155. The casing 2155 is then preferably maintained in a substantially stationary position.

10 The pressurization of the pressure chamber 2250 causes the upper sealing head 2130, outer sealing mandrel 2140 and expansion cone 2150 to move in an axial direction relative to the casing 2155. In this manner, the expansion cone 2150 will cause the casing 2155 to expand in the radial direction.

15 During the radial expansion process, the casing 2155 is prevented from moving in an upward direction by the slips 2125. A length of the casing 2155 is then expanded in the radial direction through the pressurization of the pressure chamber 2250. The length of the casing 2155 that is expanded during the expansion process will be proportional to the stroke length of the upper sealing head 2130, outer sealing mandrel 2140, and expansion cone 2150.

20 Upon the completion of a stroke, the operating pressure of the second fluidic material is reduced and the upper sealing head 2130, outer sealing mandrel 2140, and expansion cone 2150 drop to their rest positions with the casing 2155 supported by the expansion cone 2150. The position of the drillpipe 2105 is preferably adjusted throughout the radial expansion process in order to maintain the overlapping
25 relationship between the thin walled sections of the lower end of the existing wellbore casing and the upper end of the casing 2155. In a preferred embodiment, the stroking of the expansion cone 2150 is then repeated, as necessary, until the thin walled section 2265 of the upper end 2260 of the casing 2155 is expanded into the thin walled section of the lower end of the existing wellbore casing. In this manner, a wellbore

casing is formed including two adjacent sections of casing having a substantially constant inside diameter. This process may then be repeated for the entirety of the wellbore to provide a wellbore casing thousands of feet in length having a substantially constant inside diameter.

5 In a preferred embodiment, during the final stroke of the expansion cone 2150, the slips 2125 are positioned as close as possible to the thin walled section 2265 of the upper end of the casing 2155 in order minimize slippage between the casing 2155 and the existing wellbore casing at the end of the radial expansion process. Alternatively, or in addition, the outside diameter of the annular sealing member 2270 is selected
10 to ensure sufficient interference fit with the inside diameter of the lower end of the existing casing to prevent axial displacement of the casing 2155 during the final stroke. Alternatively, or in addition, the outside diameter of the annular sealing member 2285 is selected to provide an interference fit with the inside walls of the wellbore at an earlier point in the radial expansion process so as to prevent further
15 axial displacement of the casing 2155. In this final alternative, the interference fit is preferably selected to permit expansion of the casing 2155 by pulling the expansion cone 2150 out of the wellbore, without having to pressurize the pressure chamber 2250.

20 During the radial expansion process, the pressurized areas of the apparatus 2100 are limited to the fluid passages 2160, 2165, 2170, and 2175, the pressure chambers 2195 within the slips 2125, and the pressure chamber 2250. No fluid pressure acts directly on the casing 2155. This permits the use of operating pressures higher than the casing 2155 could normally withstand.

25 Once the casing 2155 has been completely expanded off of the expansion cone 2150, remaining portions of the apparatus 2100 are removed from the wellbore. In a preferred embodiment, the contact pressure between the deformed thin wall sections and compressible annular members of the lower end of the existing casing and the upper end 2260 of the casing 2155 ranges from about 500 to 40,000 psi in order to optimally support the casing 2155 using the existing wellbore casing.

In this manner, the casing 2155 is radially expanded into contact with an existing section of casing by pressurizing the interior fluid passages 2160, 2165, 2170, and 2175 and the pressure chamber 2250 of the apparatus 2100.

In a preferred embodiment, as required, the annular body of hardenable fluidic material is then allowed to cure to form a rigid outer annular body about the expanded casing 2155. In the case where the casing 2155 is slotted, the cured fluidic material preferably permeates and envelops the expanded casing 2155. The resulting new section of wellbore casing includes the expanded casing 2155 and the rigid outer annular body. The overlapping joint between the pre-existing wellbore casing and the expanded casing 2155 includes the deformed thin wall sections and the compressible outer annular bodies. The inner diameter of the resulting combined wellbore casings is substantially constant. In this manner, a mono-diameter wellbore casing is formed. This process of expanding overlapping tubular members having thin wall end portions with compressible annular bodies into contact can be repeated for the entire length of a wellbore. In this manner, a mono-diameter wellbore casing can be provided for thousands of feet in a subterranean formation.

In a preferred embodiment, as the expansion cone 2150 nears the upper end of the casing 2155, the operating flow rate of the second fluidic material is reduced in order to minimize shock to the apparatus 2100. In an alternative embodiment, the apparatus 2100 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 2155.

In a preferred embodiment, the reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 2130 nears the end of the casing 2155 in order to optimally provide reduced axial movement and velocity of the expansion cone 2130. In a preferred embodiment, the operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 2100 to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone 2130 during the return stroke. In a preferred embodiment, the stroke length of the apparatus 2100 ranges from about 10 to 45 feet

in order to optimally provide equipment lengths that can be handled by conventional oil well rigging equipment while also minimizing the frequency at which the expansion cone 2130 must be stopped so that the apparatus 2100 can be re-stroked.

5 In an alternative embodiment, at least a portion of the upper sealing head 2130 includes an expansion cone for radially expanding the casing 2155 during operation of the apparatus 2100 in order to increase the surface area of the casing 2155 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

10 Alternatively, the apparatus 2100 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 2100 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 2100 may be used to expand a tubular support member in a hole.

15 Referring now to Figures 17, 17a and 17b, another embodiment of an apparatus 2300 for expanding a tubular member will be described. The apparatus 2300 preferably includes a drillpipe 2305, an innerstring adapter 2310, a sealing sleeve 2315, a hydraulic slip body 2320, hydraulic slips 2325, an inner sealing mandrel 2330, an upper sealing head 2335, a lower sealing head 2340, a load mandrel 2345, an outer sealing mandrel 2350, an expansion cone 2355, a mechanical slip body 20 2360, mechanical slips 2365, drag blocks 2370, casing 2375, fluid passages 2380, 2385, 2390, 2395, 2400, 2405, 2410, 2415, and 2485, and mandrel launcher 2480.

25 The drillpipe 2305 is coupled to the innerstring adapter 2310. During operation of the apparatus 2300, the drillpipe 2305 supports the apparatus 2300. The drillpipe 2305 preferably comprises a substantially hollow tubular member or members. The drillpipe 2305 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. In a preferred embodiment, the drillpipe 2305 is fabricated from coiled tubing in order to facilitate the placement of the apparatus 2300 in non-vertical wellbores. The

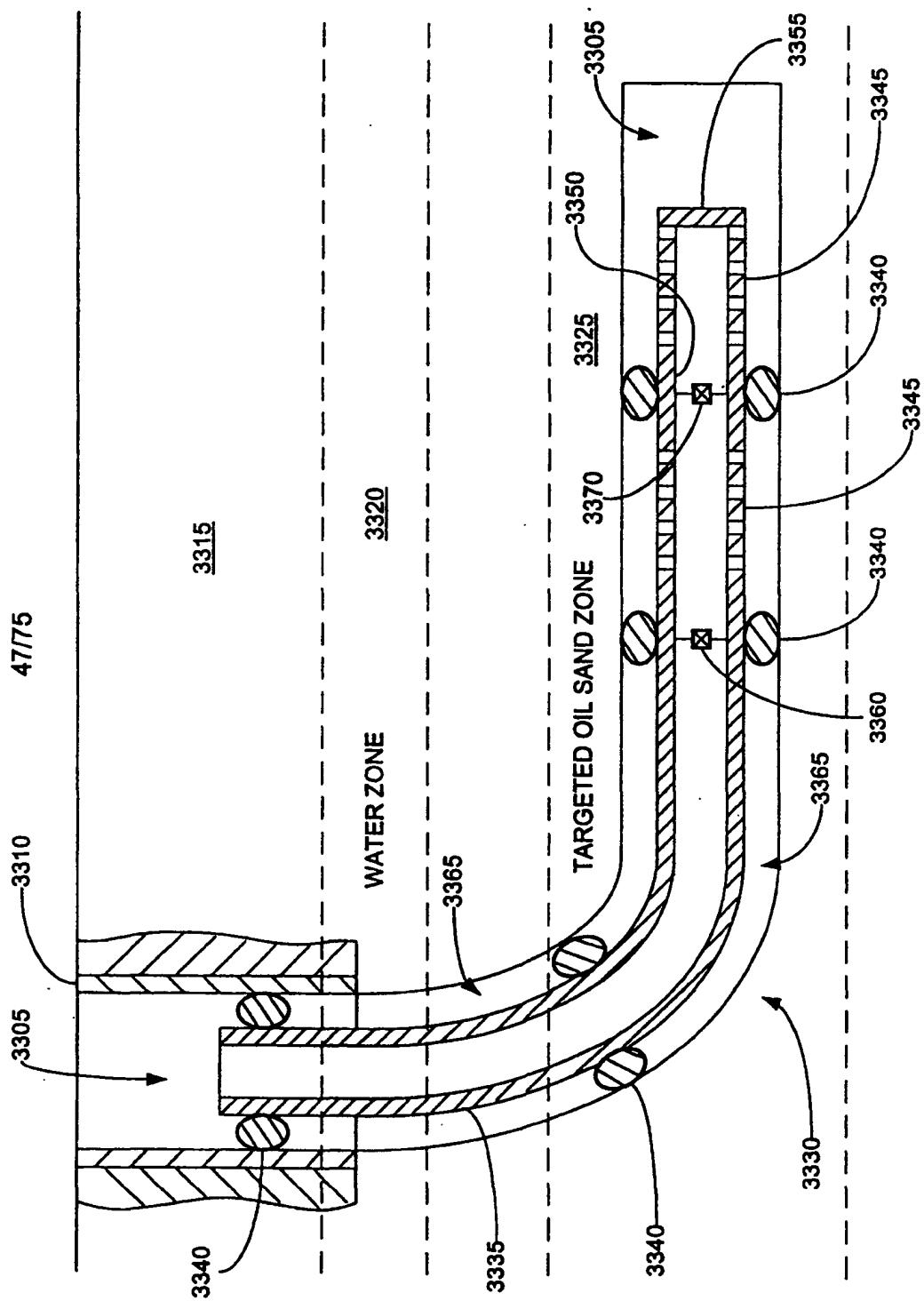


FIGURE 21

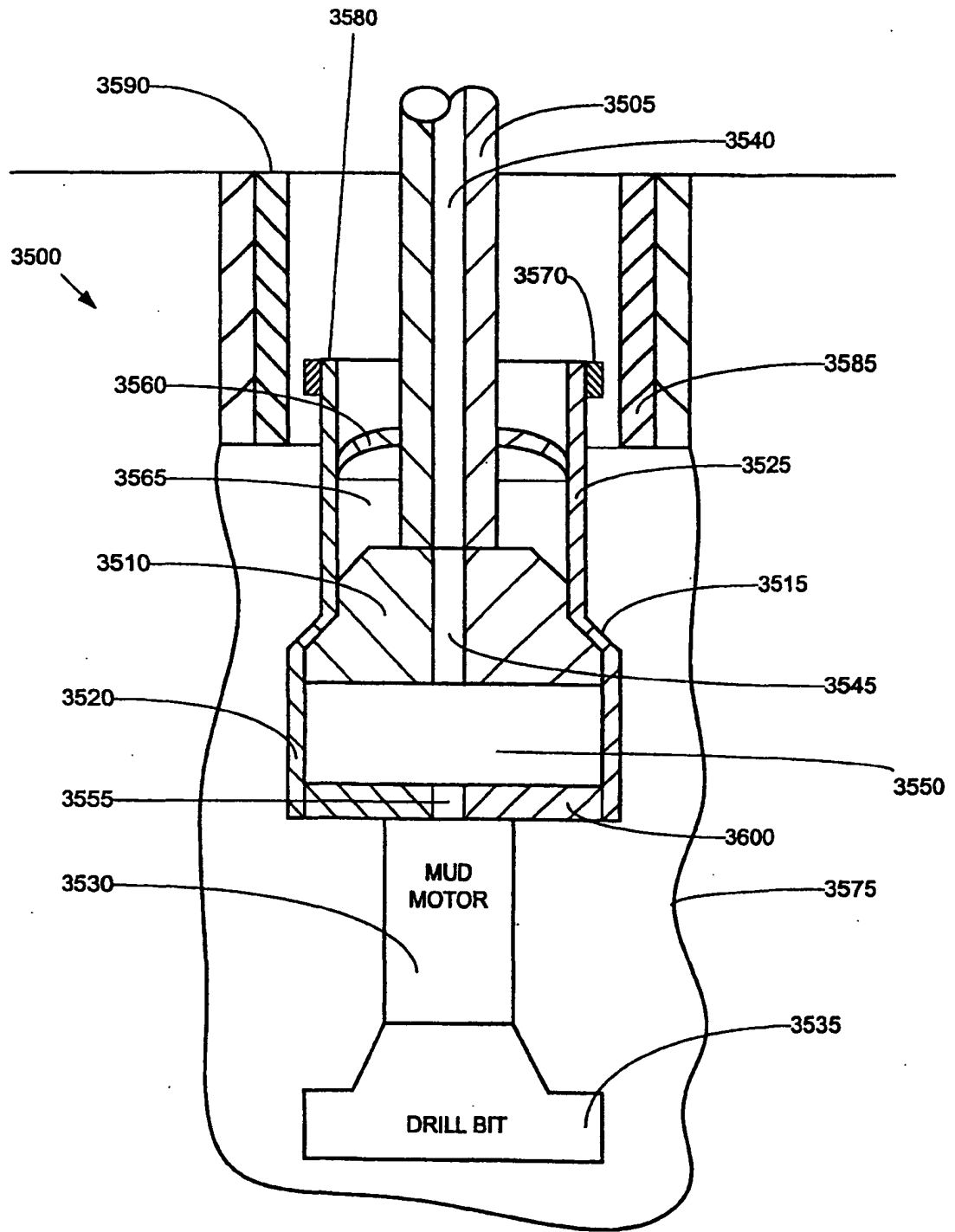


FIGURE 22A

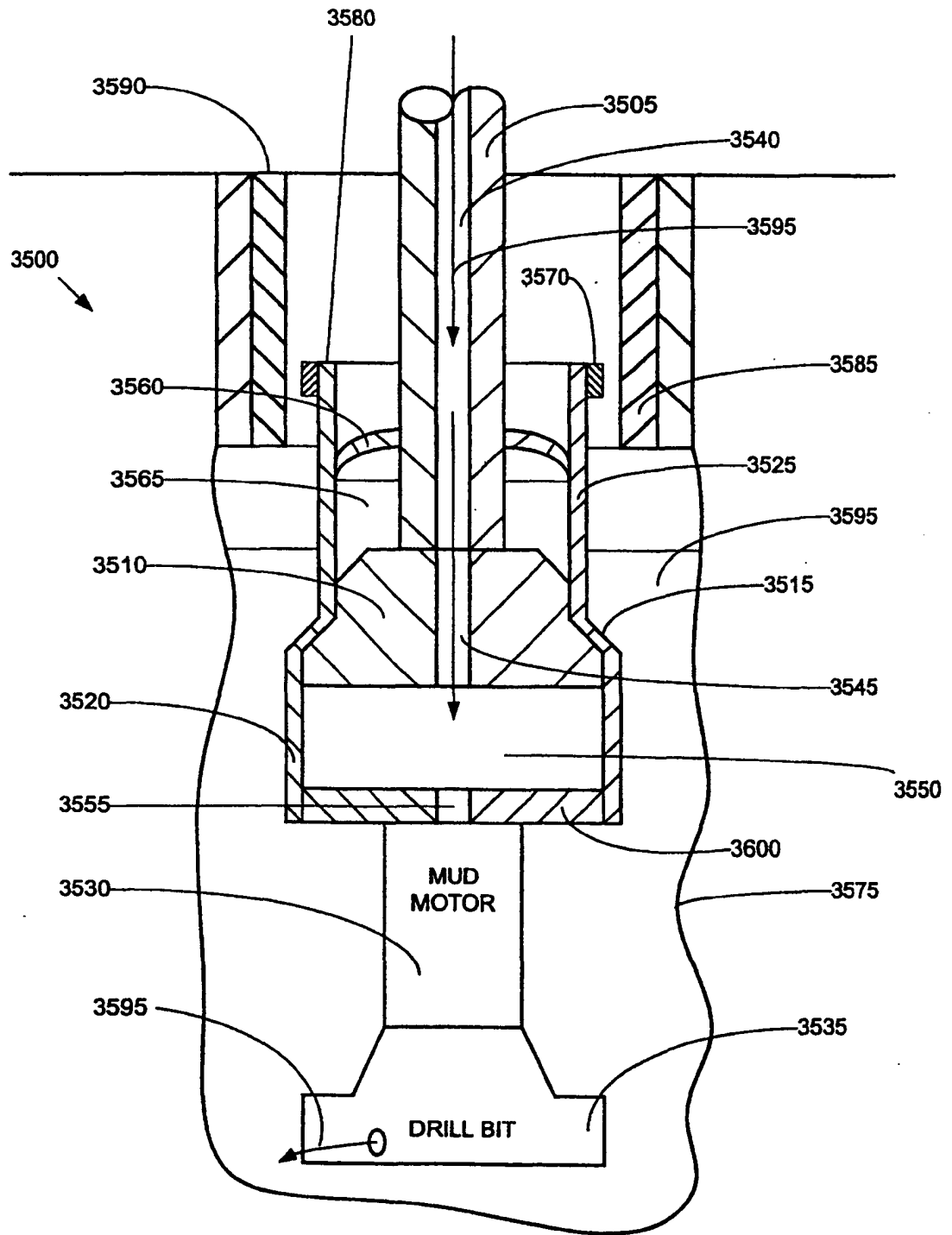


FIGURE 22B

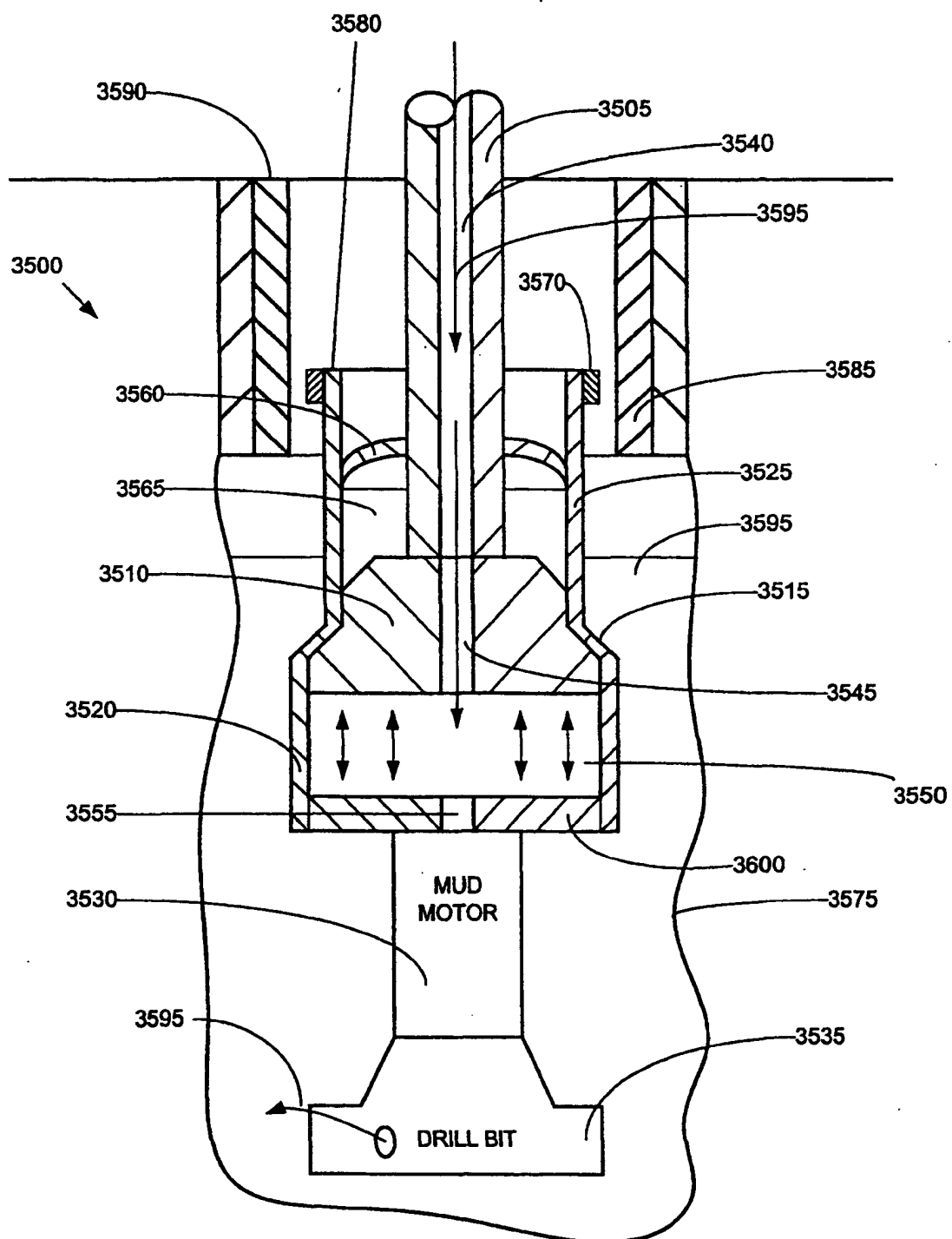


FIGURE 22C

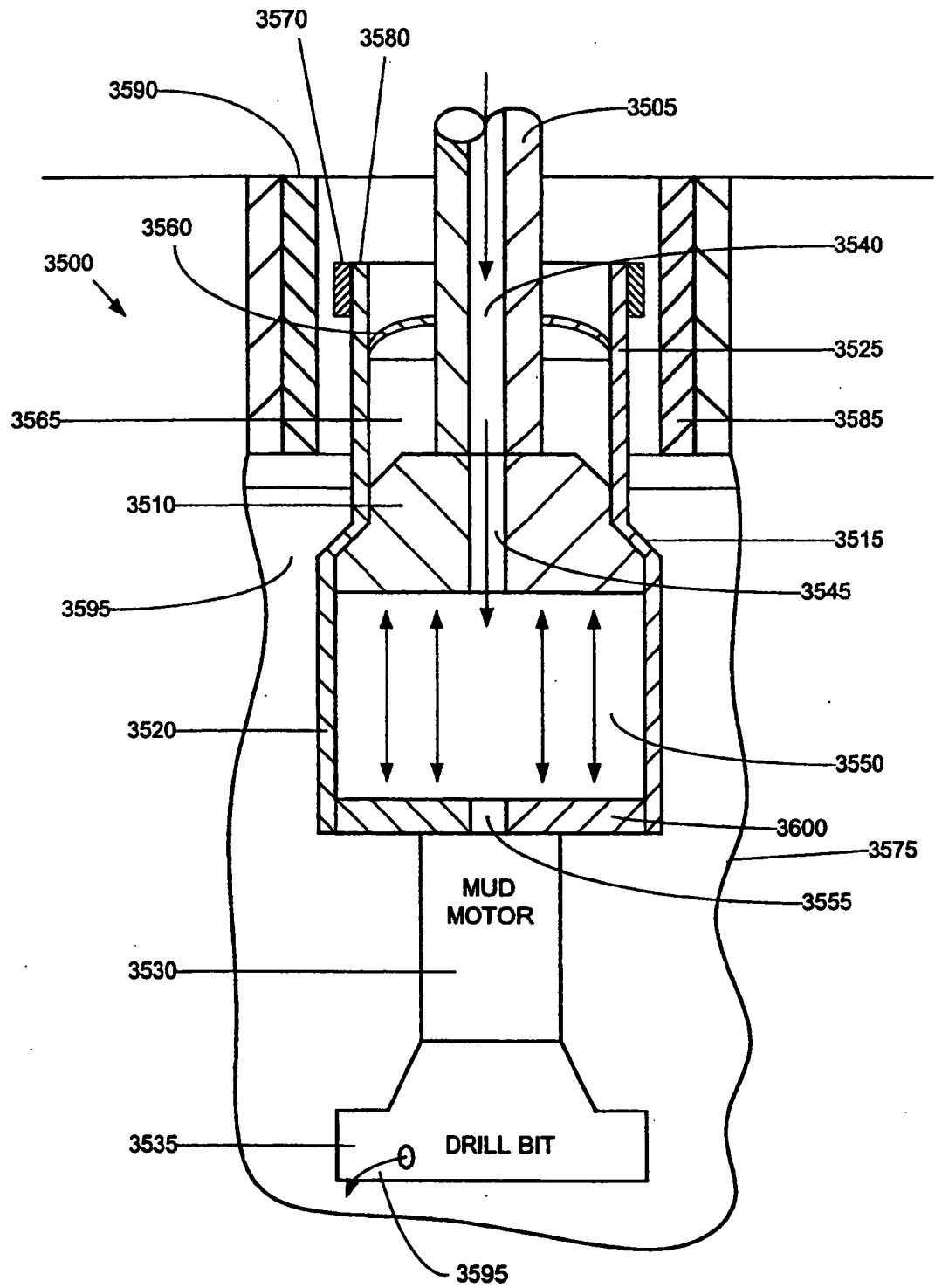


FIGURE 22D

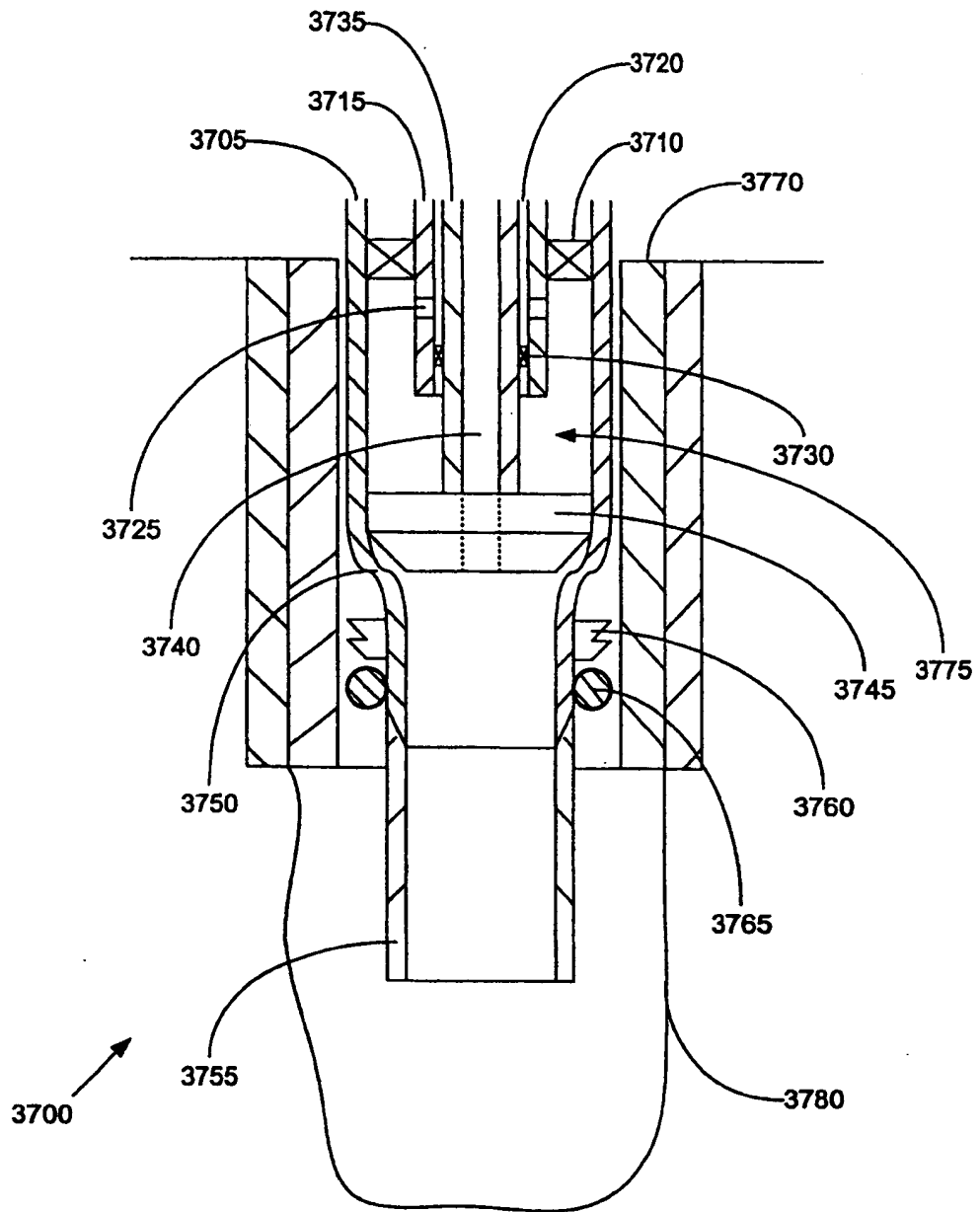


FIGURE 23A

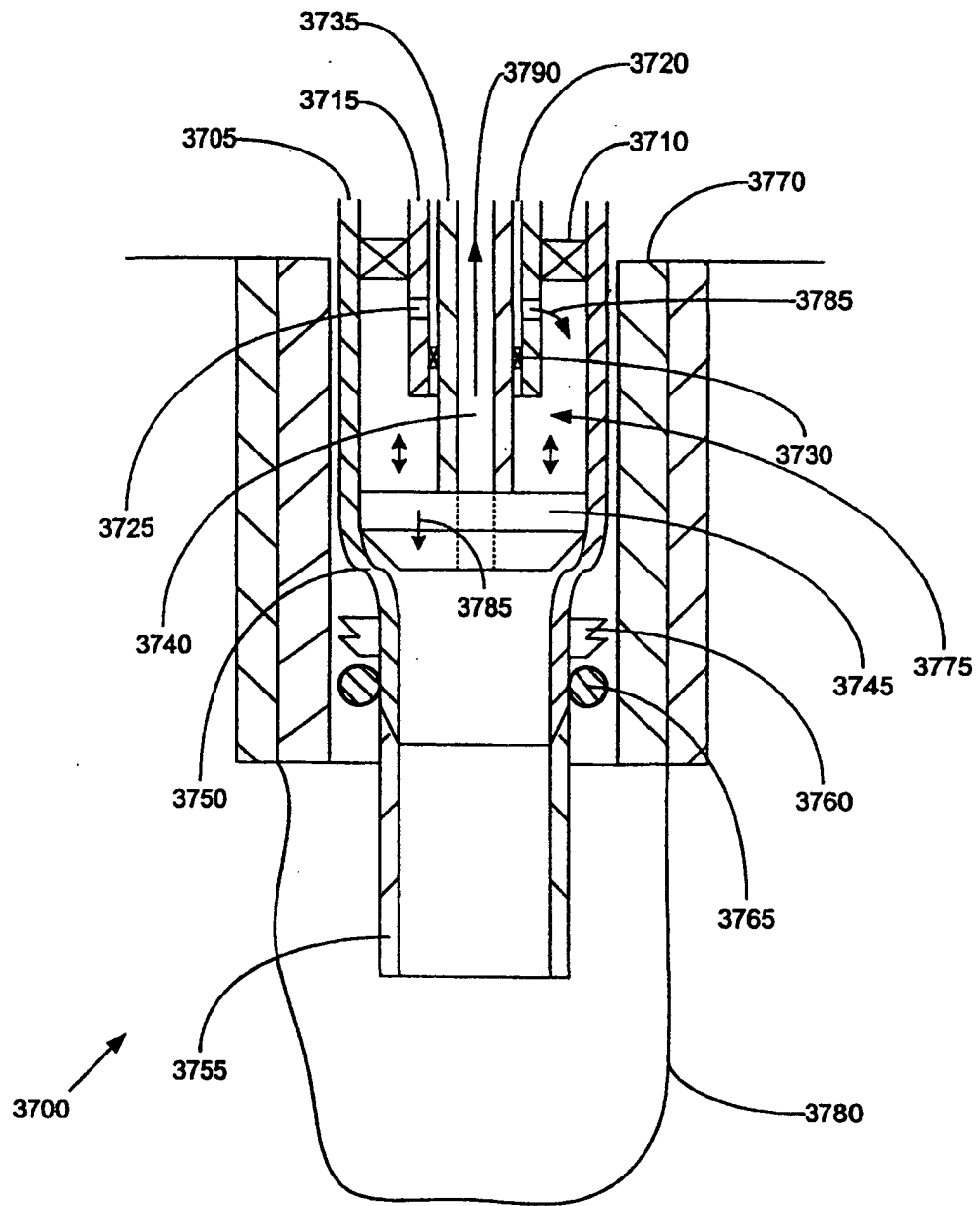


FIGURE 23B

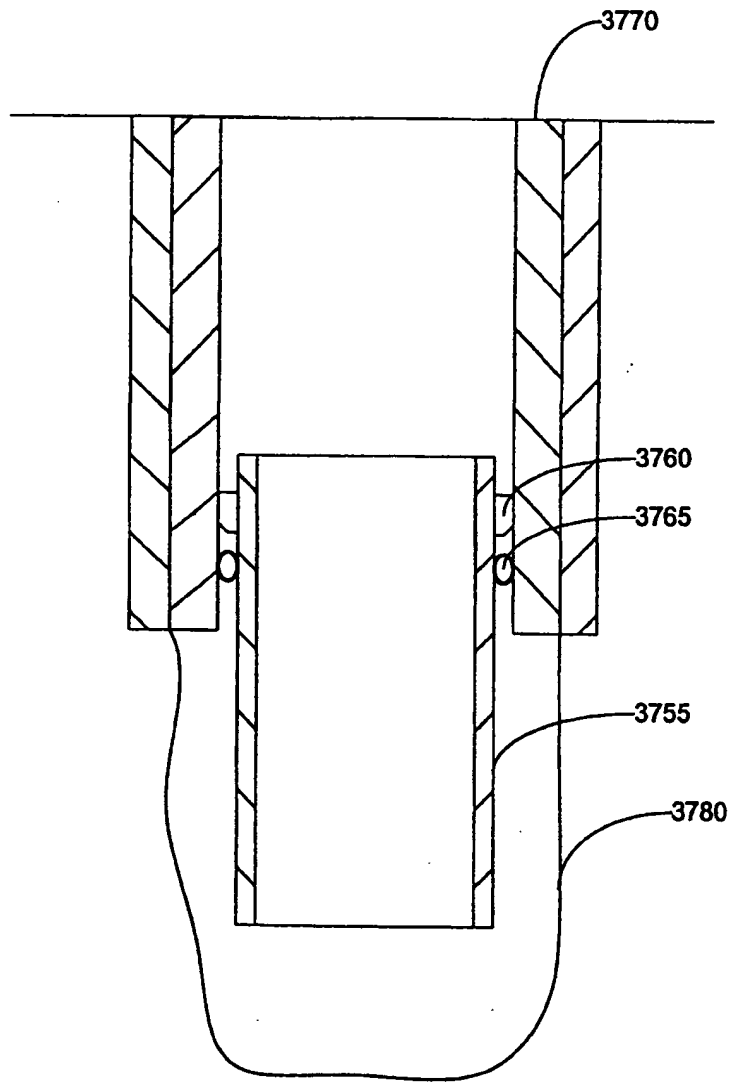


FIGURE 23C

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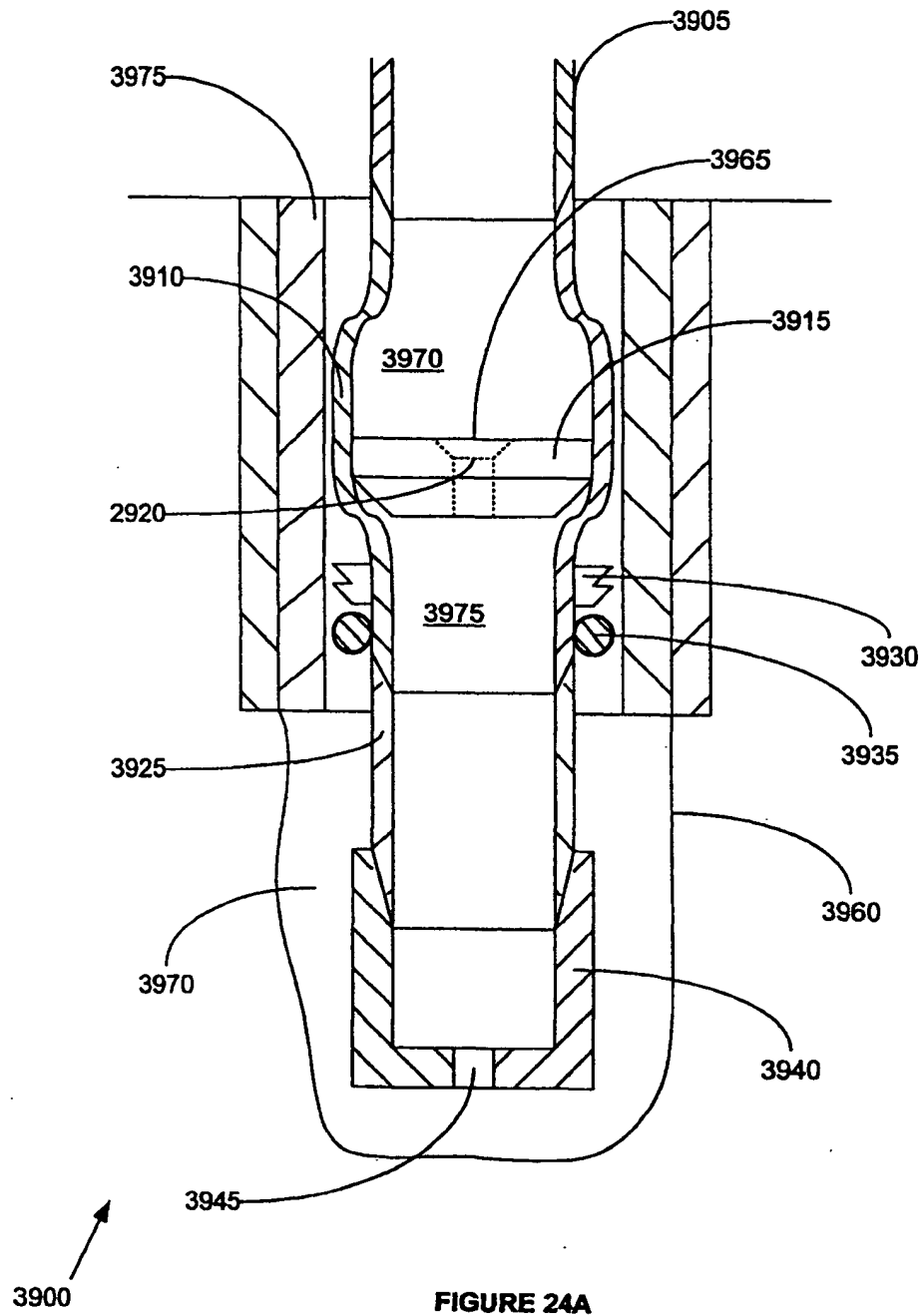


FIGURE 24A

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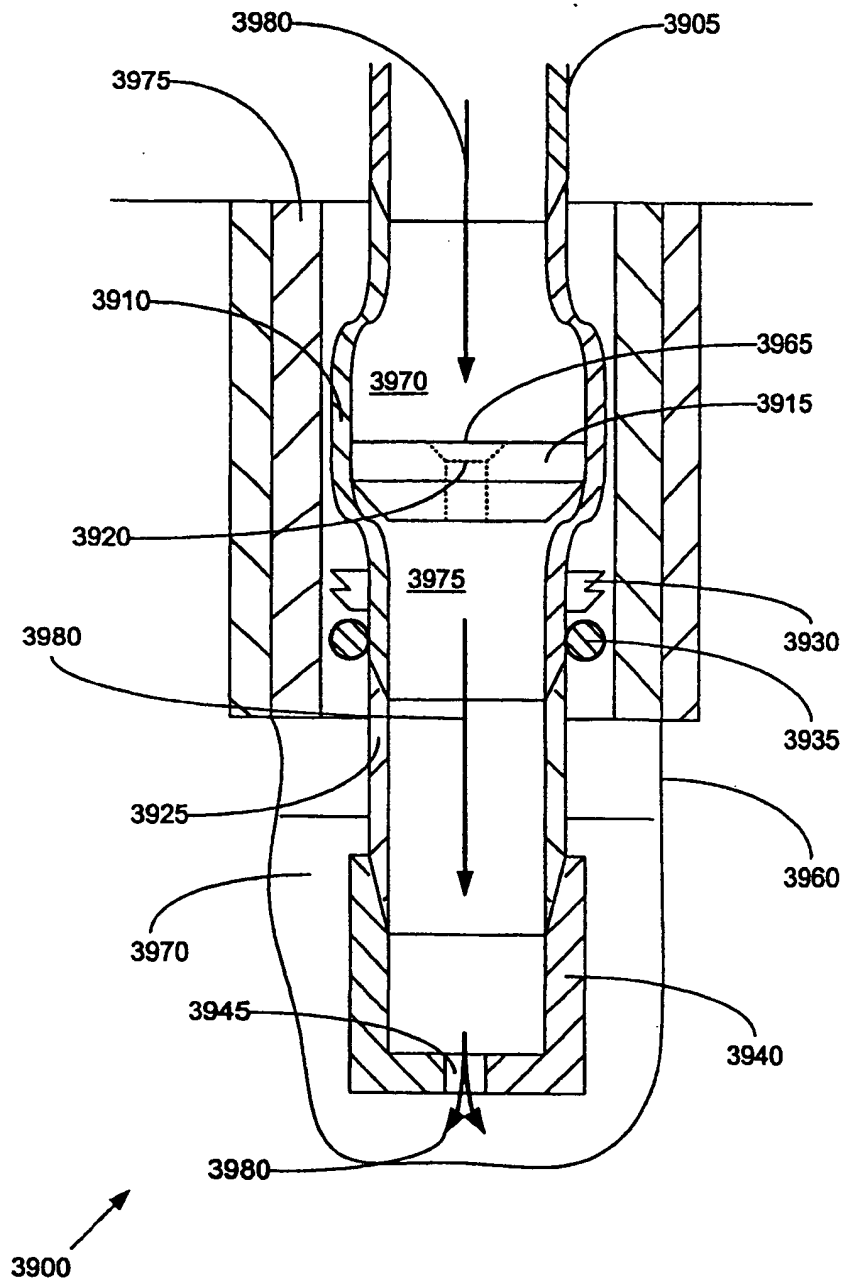


FIGURE 24B

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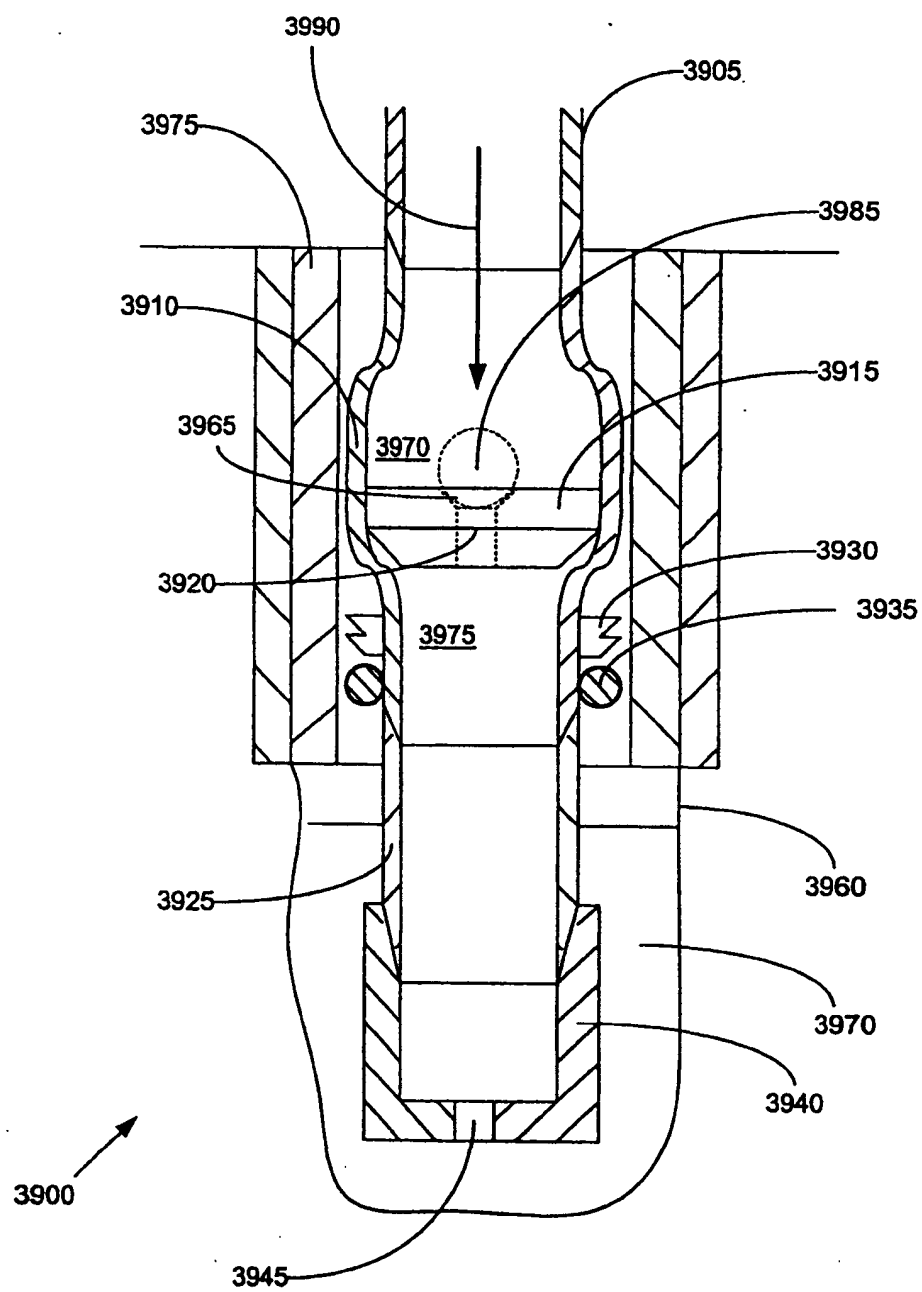


FIGURE 24C

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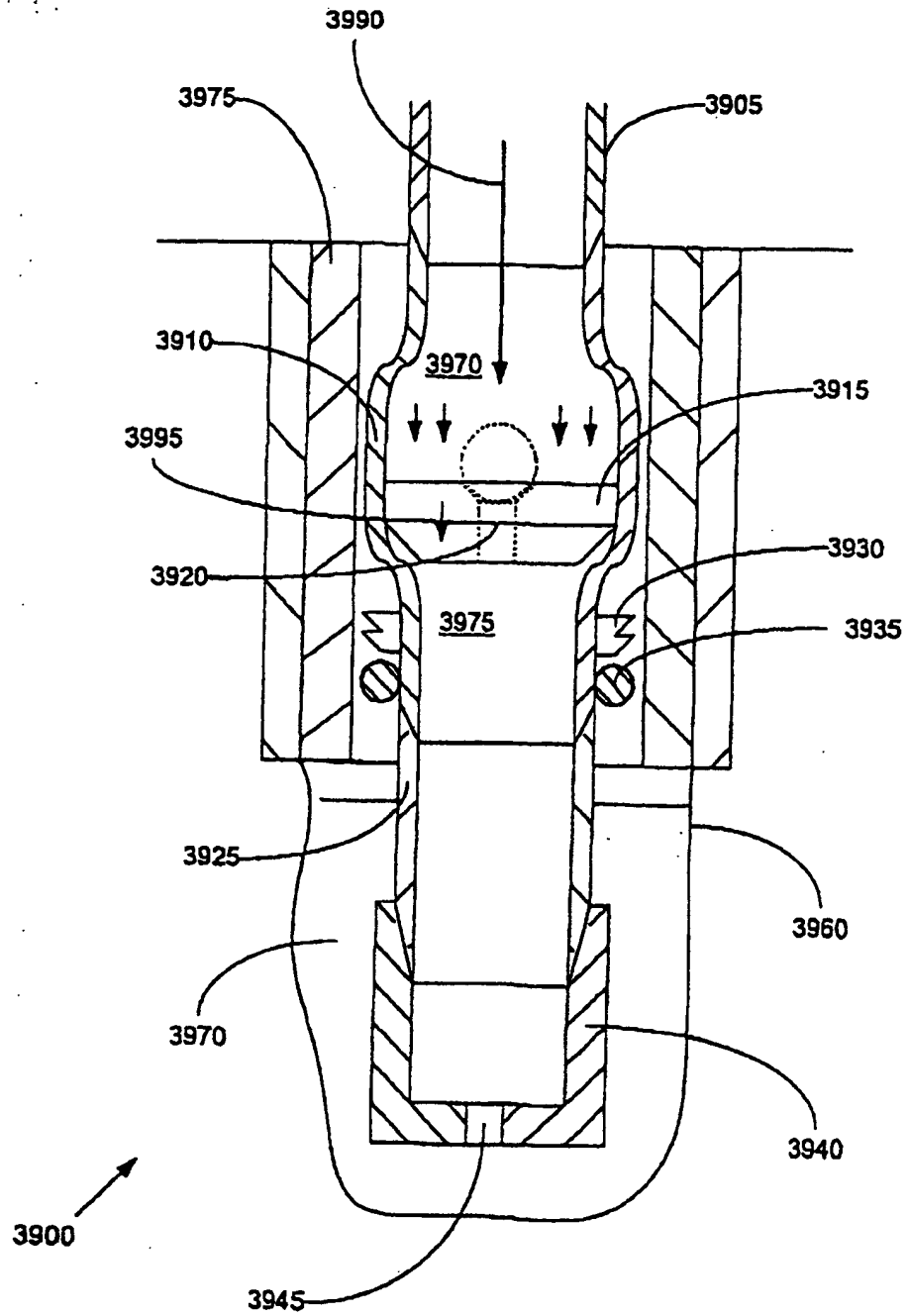


FIGURE 24D

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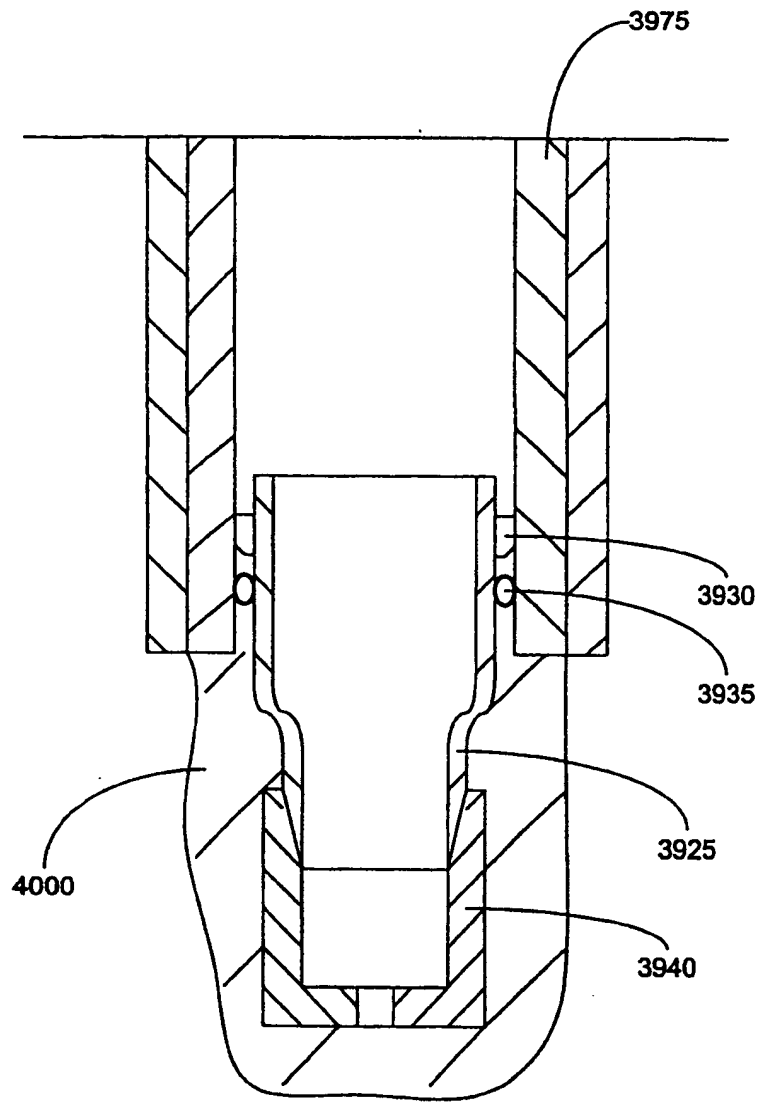


FIGURE 24E

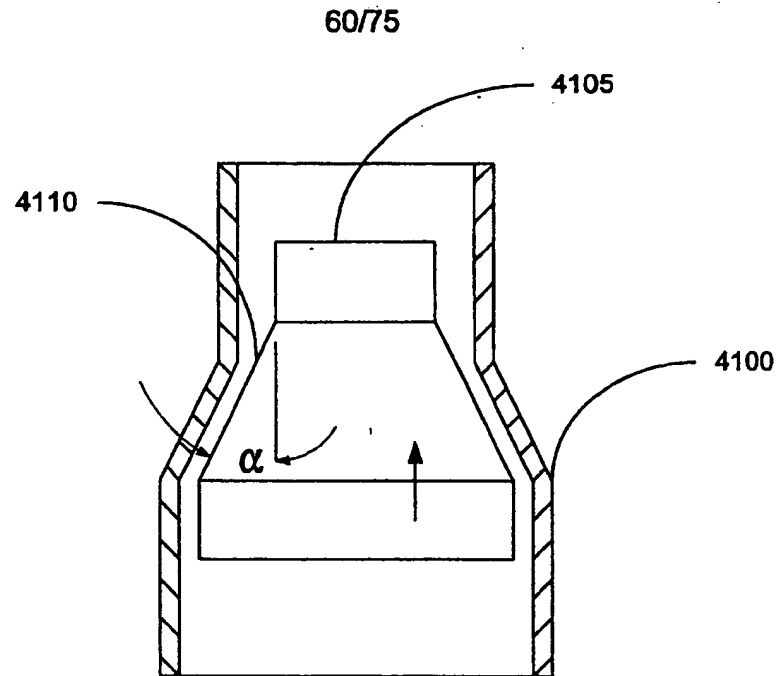


FIGURE 25

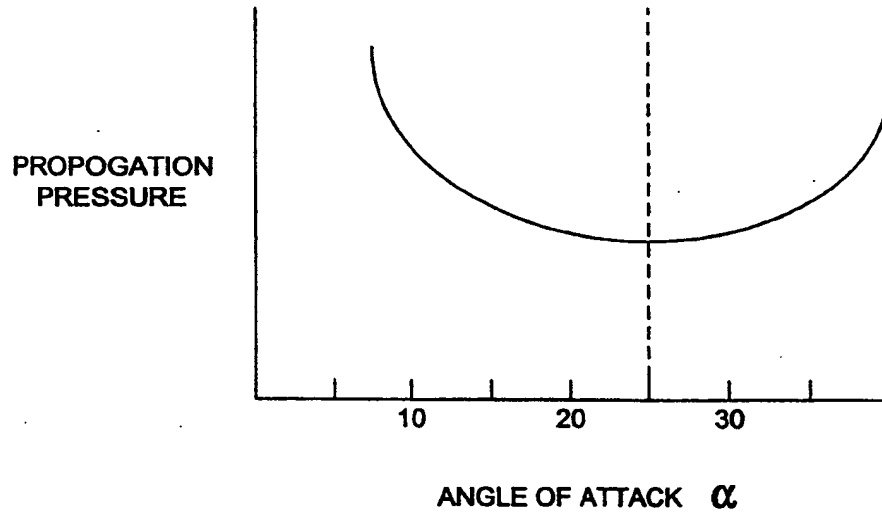


FIGURE 26

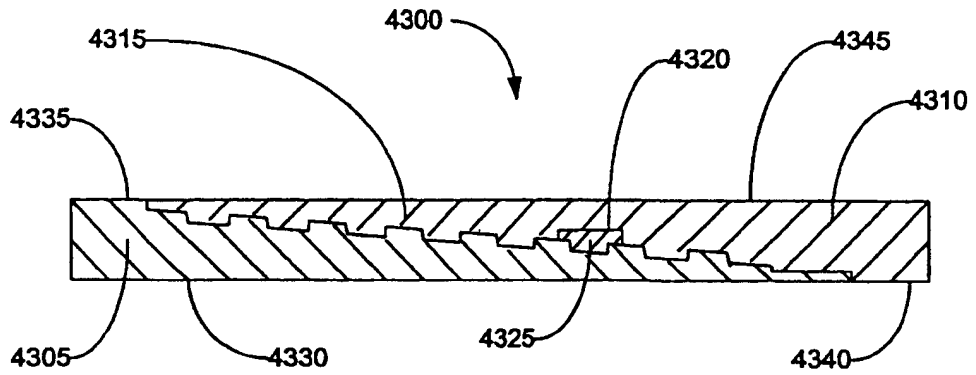


FIGURE 27

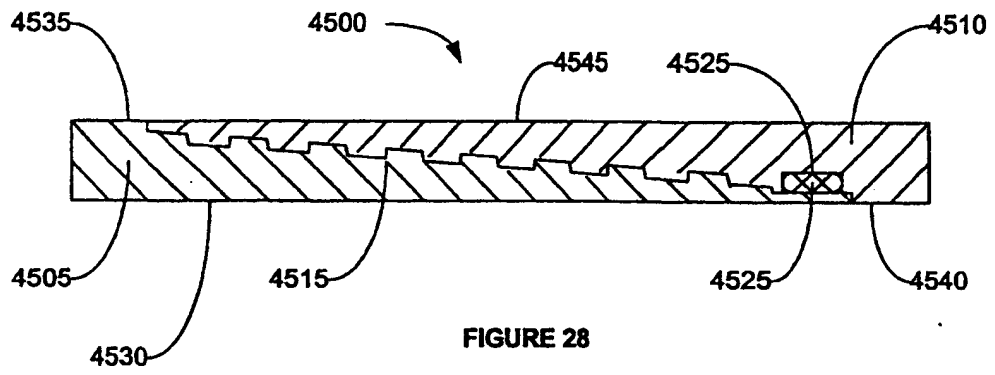


FIGURE 28

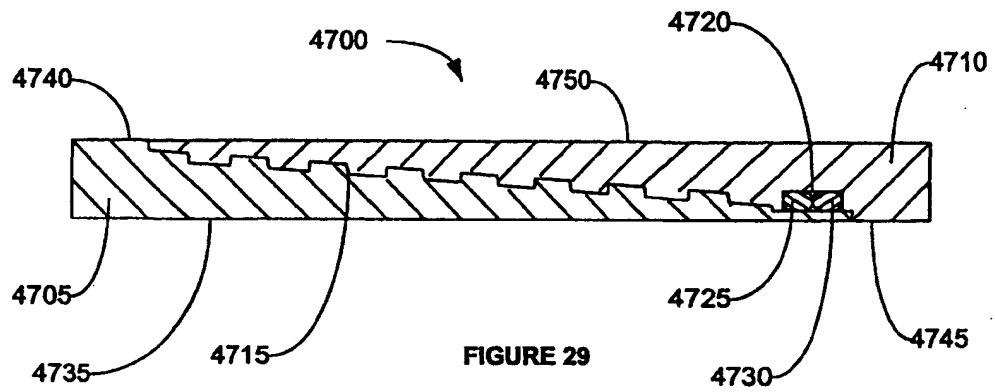
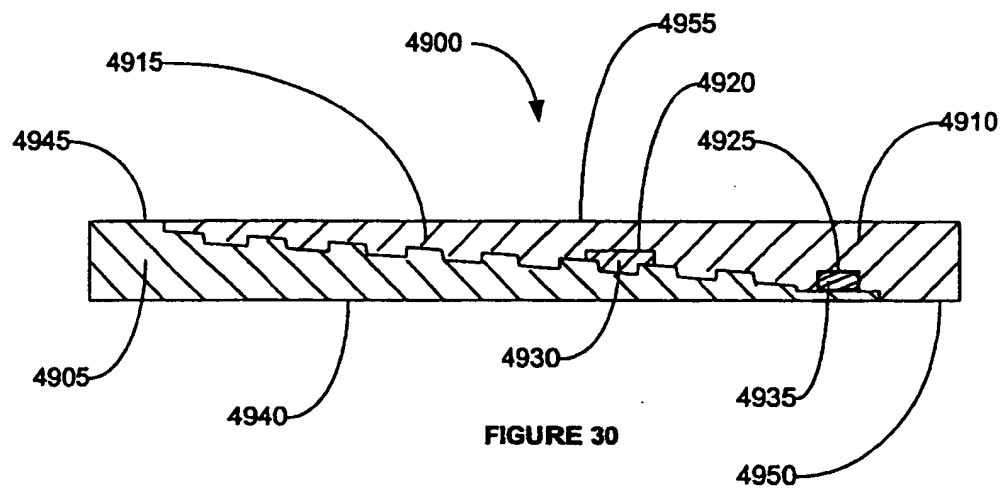


FIGURE 29



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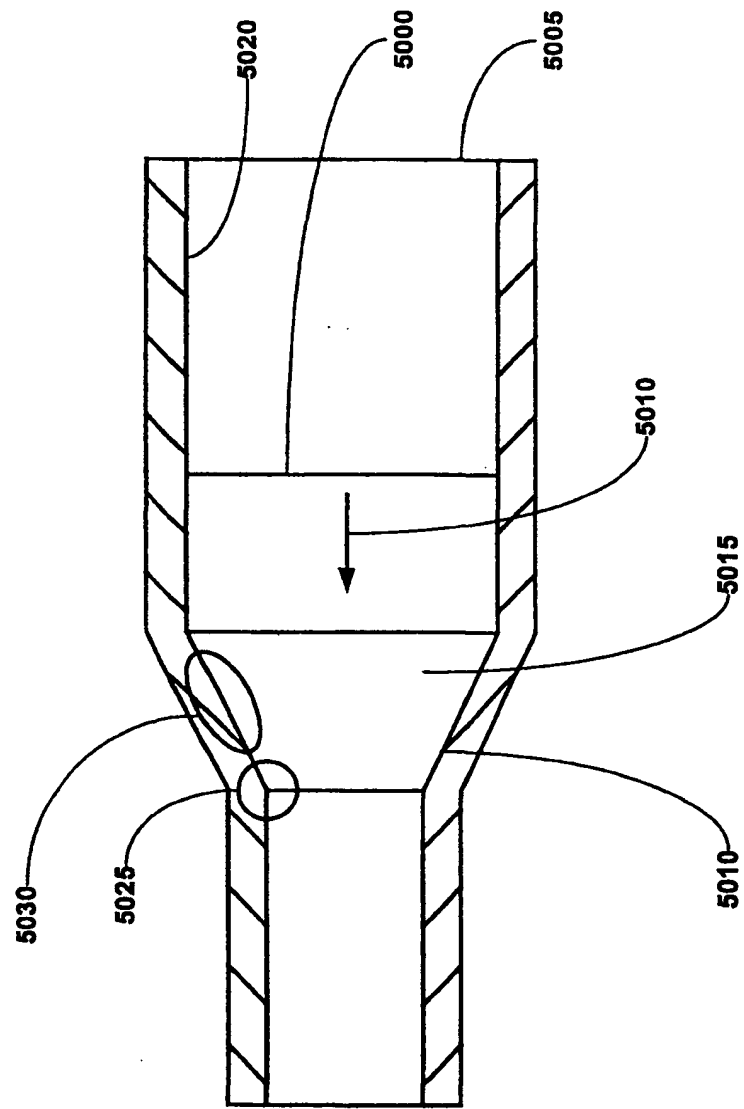
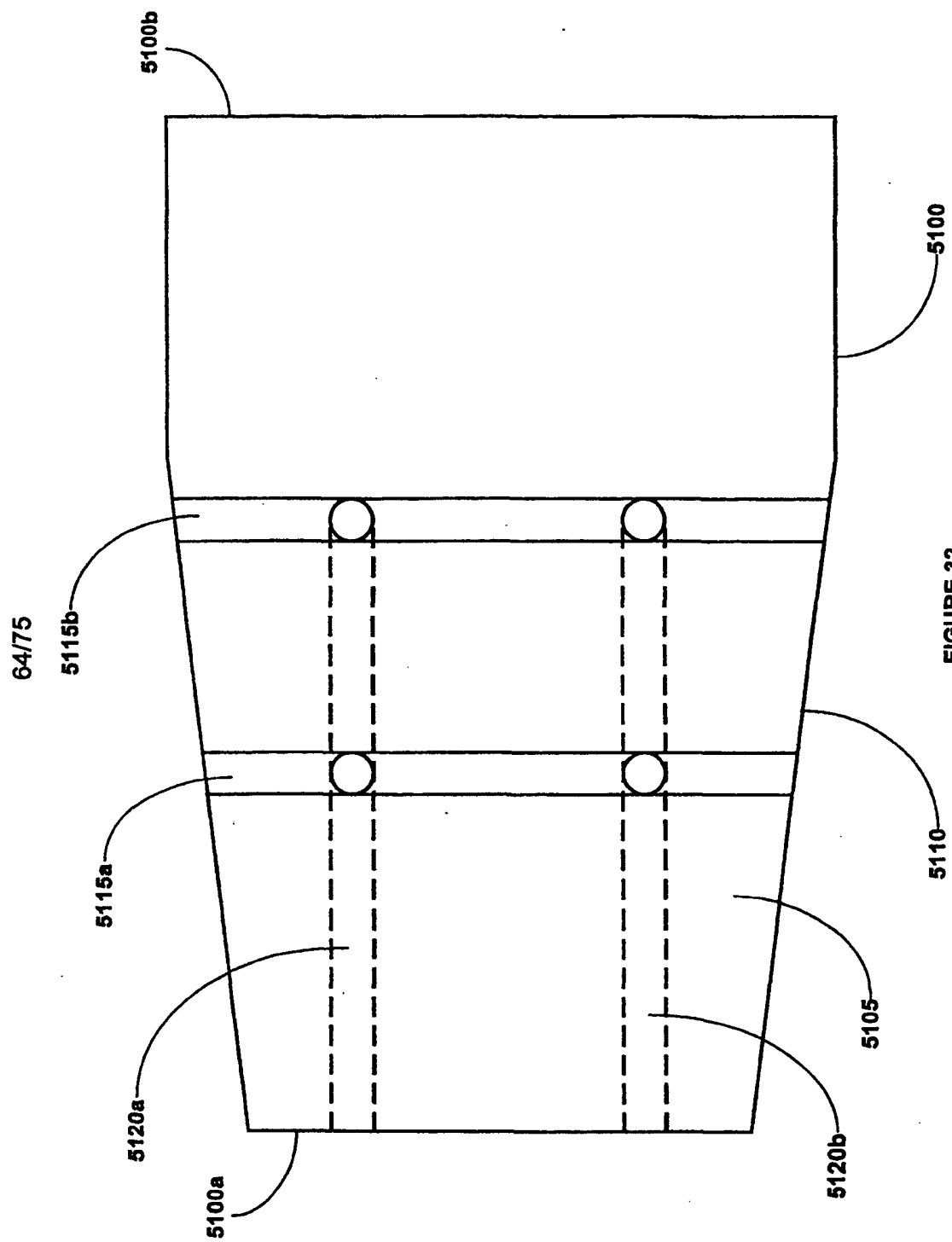


FIGURE 31



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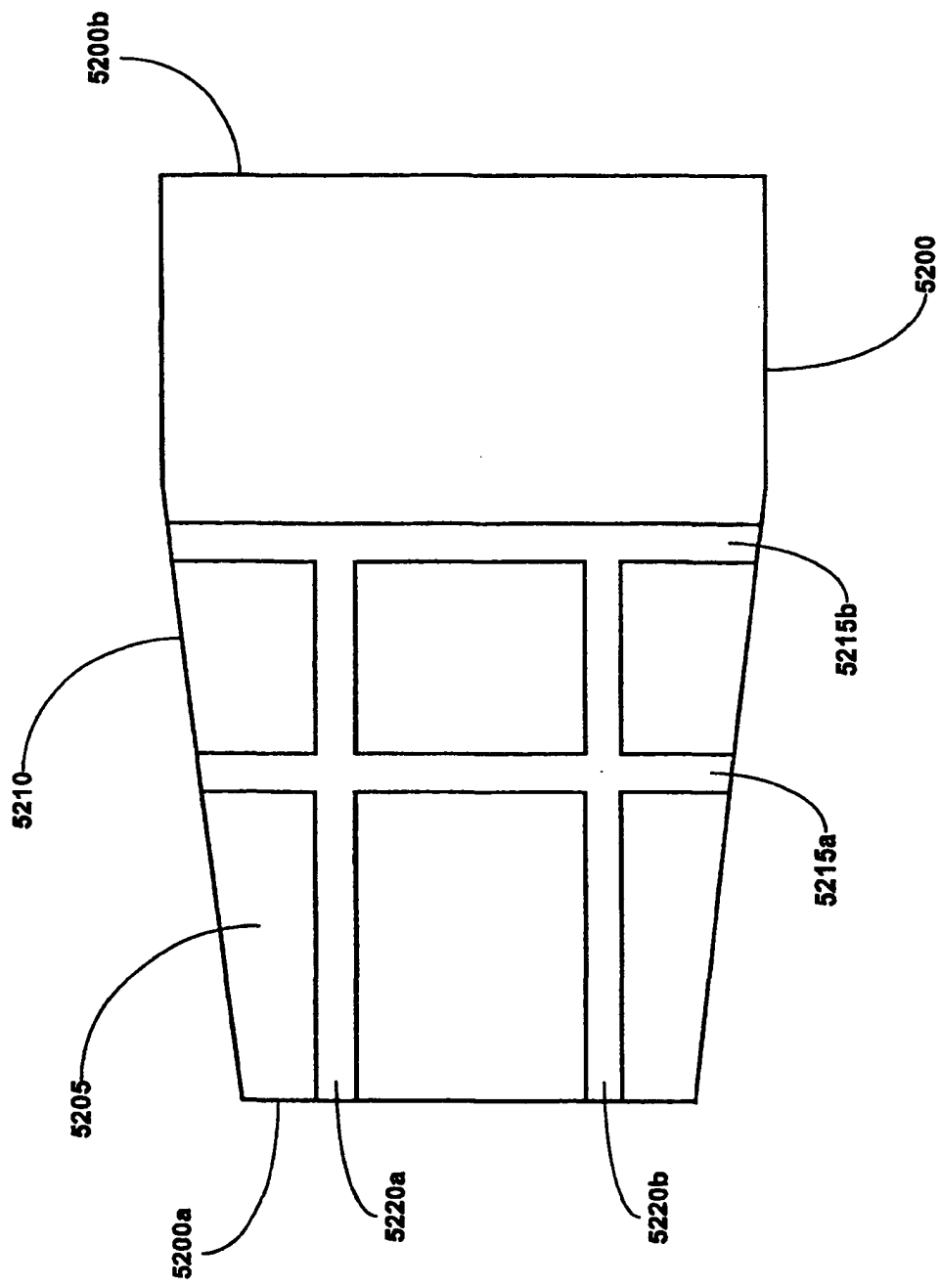


FIGURE 33

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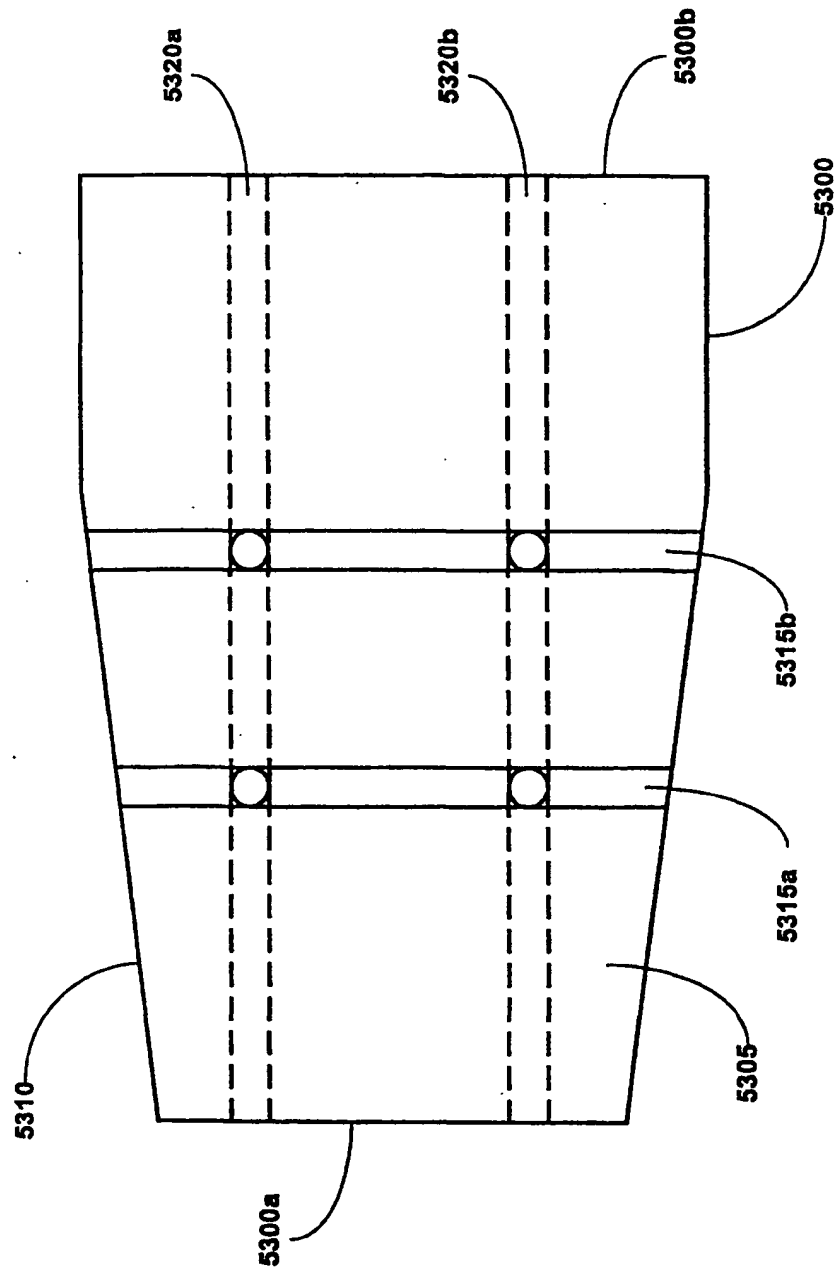


FIGURE 34

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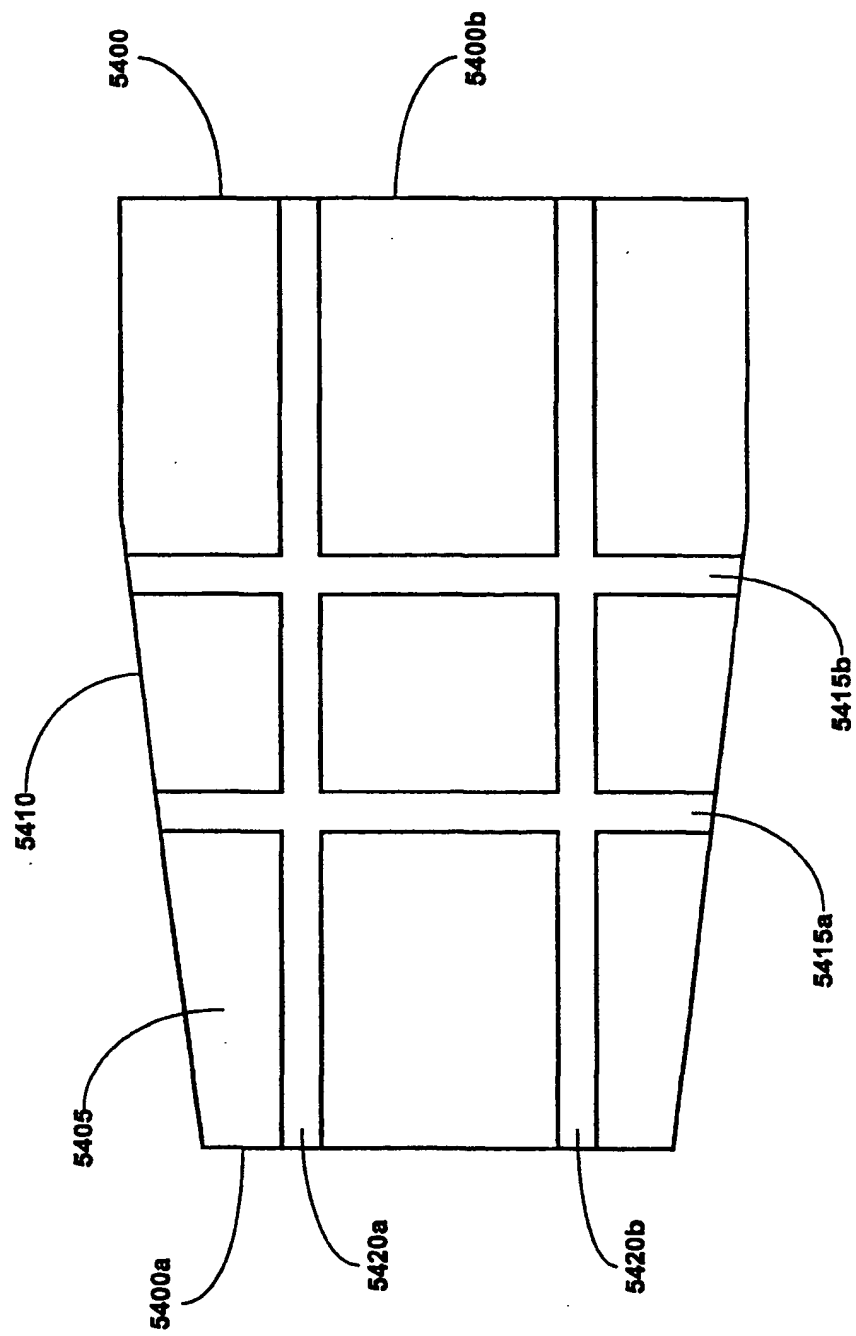


FIGURE 35

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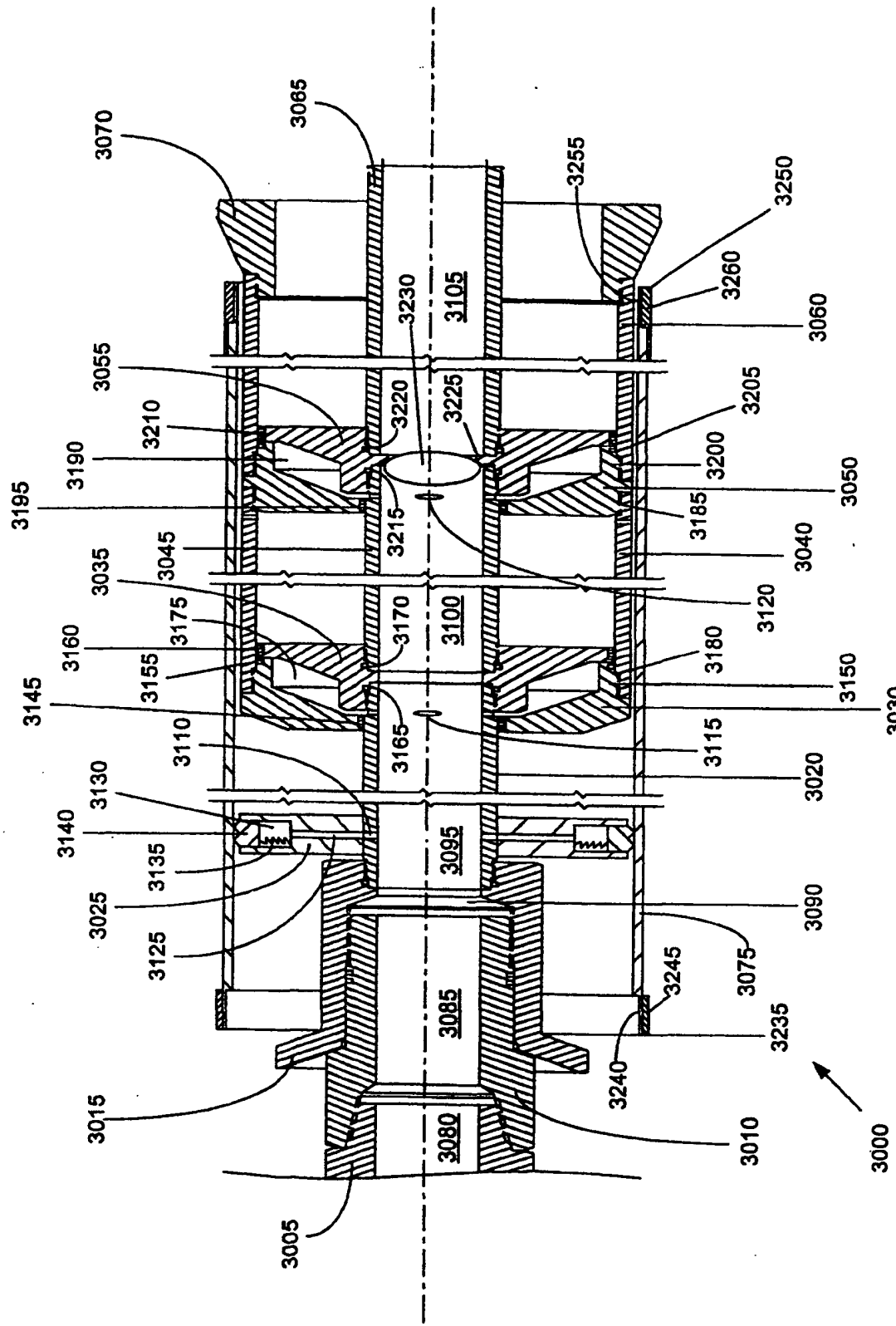


FIGURE 20

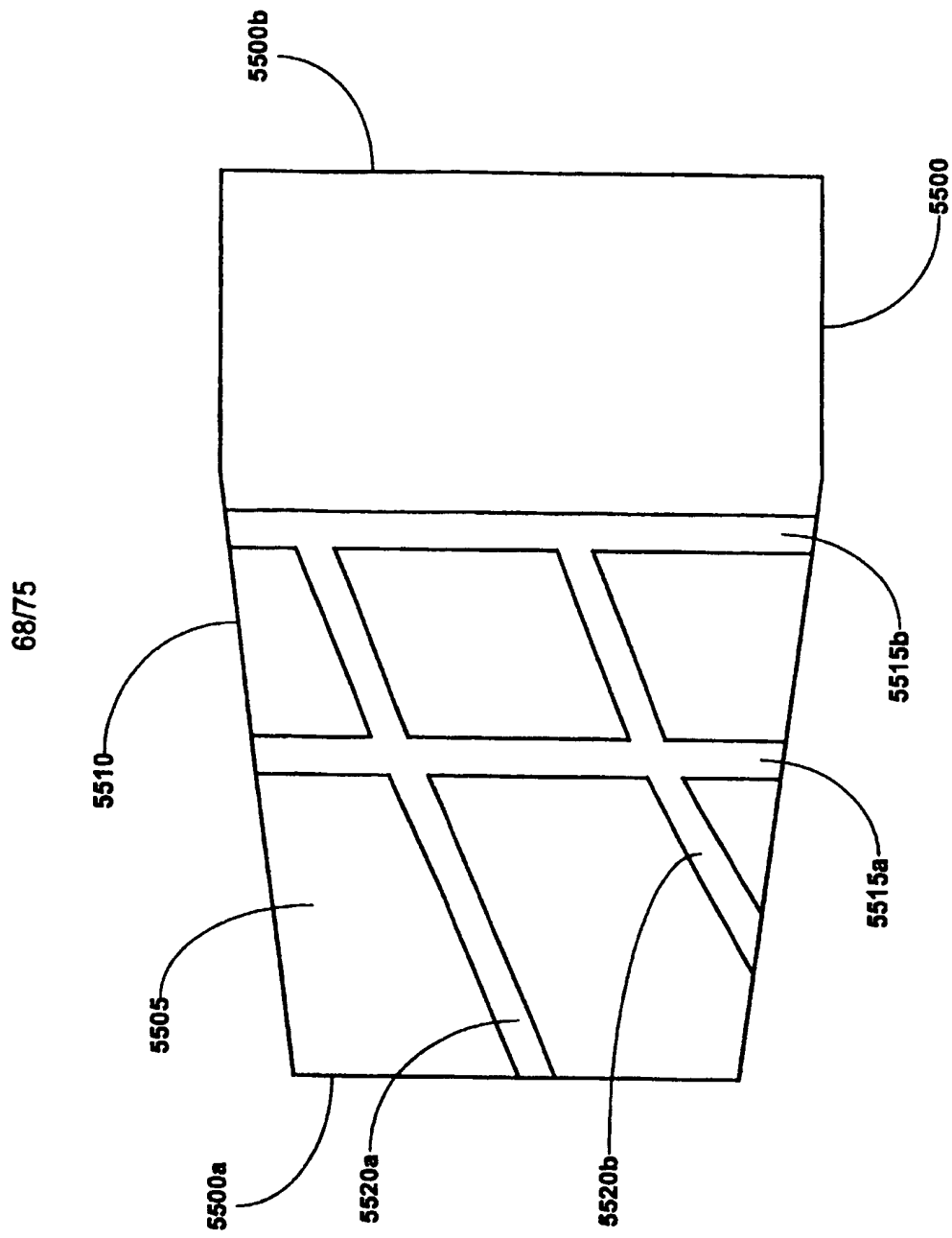


FIGURE 36

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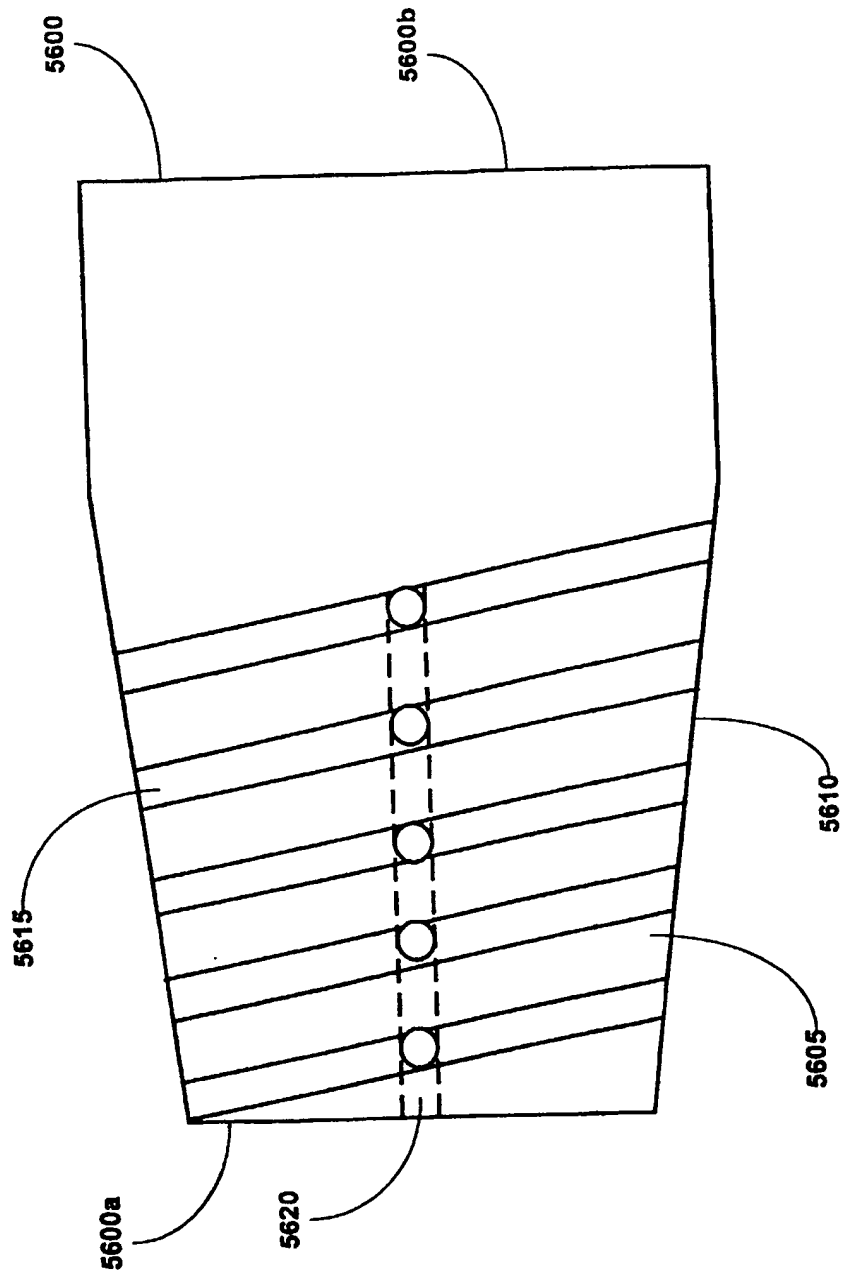


FIGURE 37

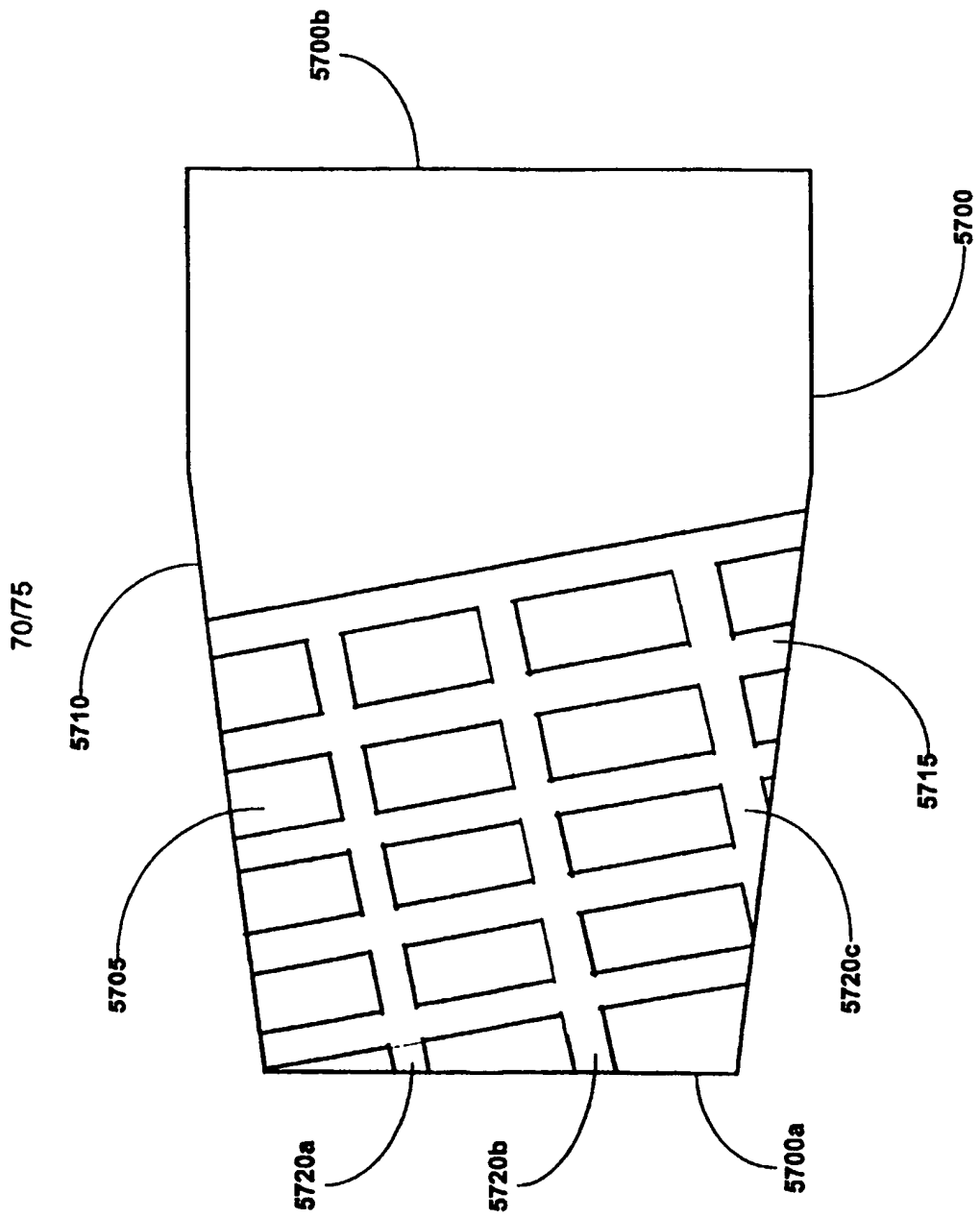


FIGURE 38

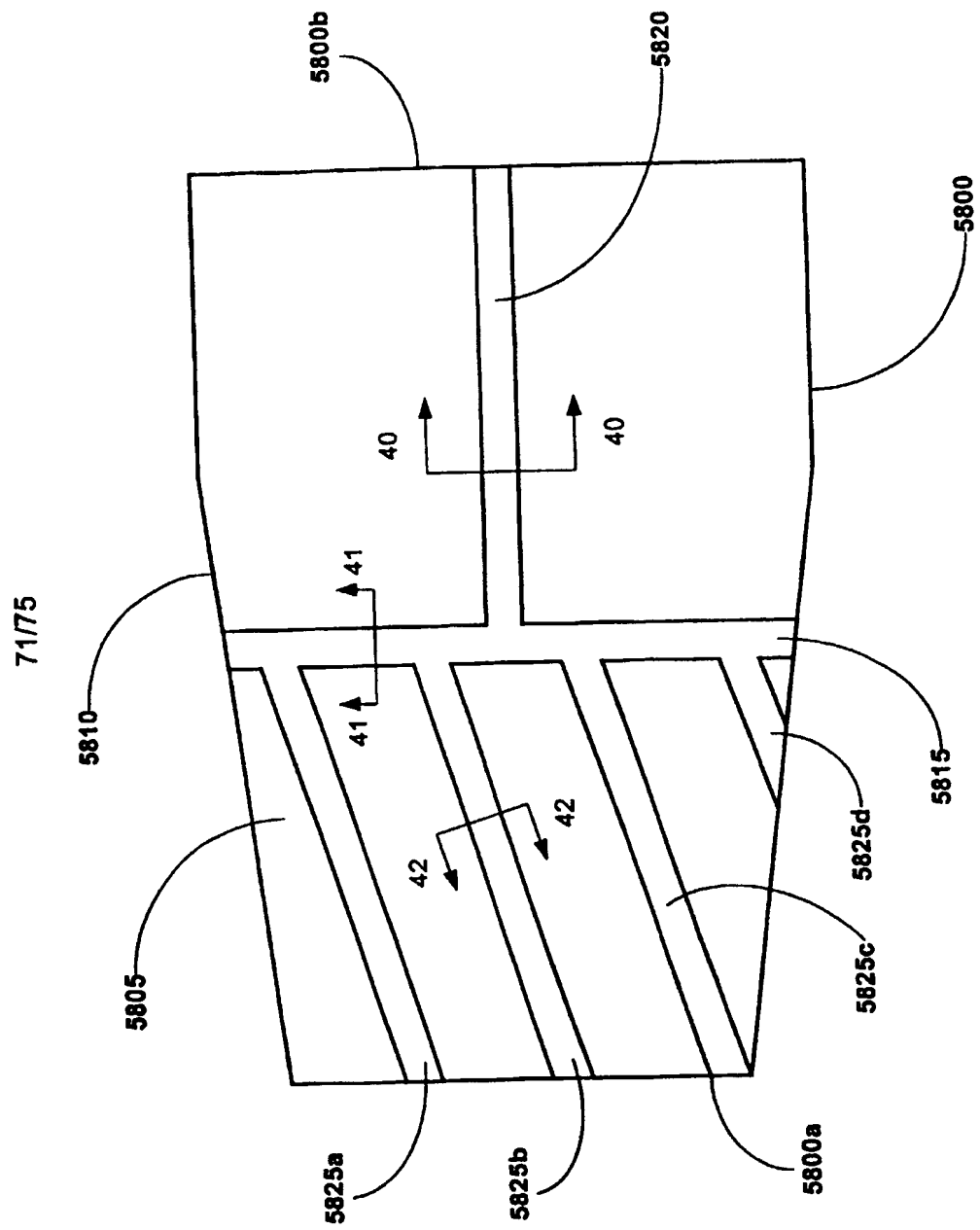


FIGURE 39

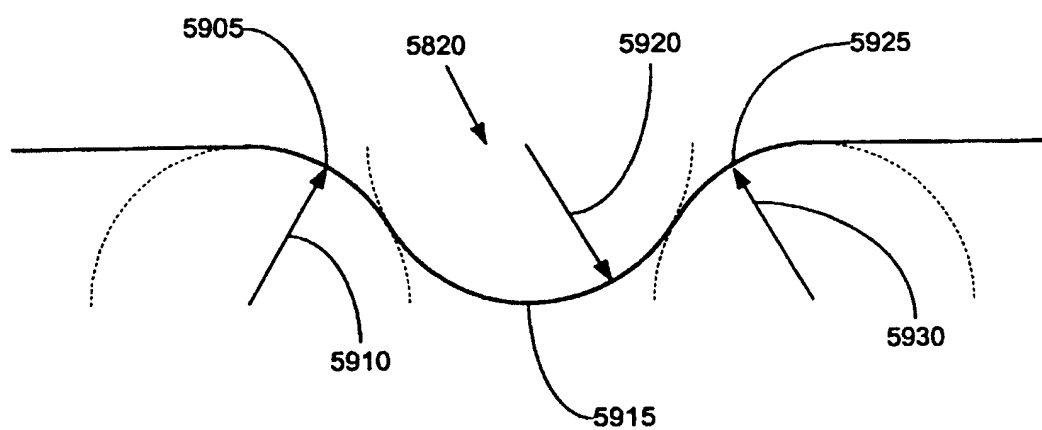


FIGURE 40

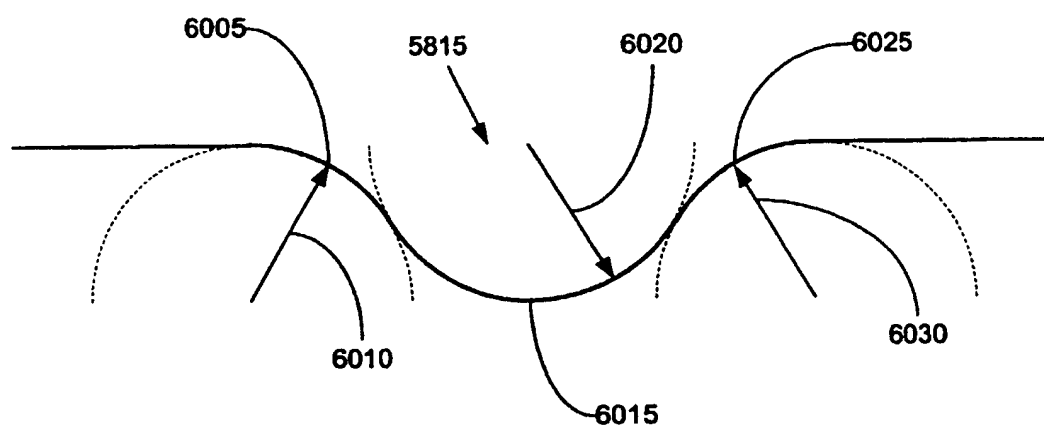


FIGURE 41

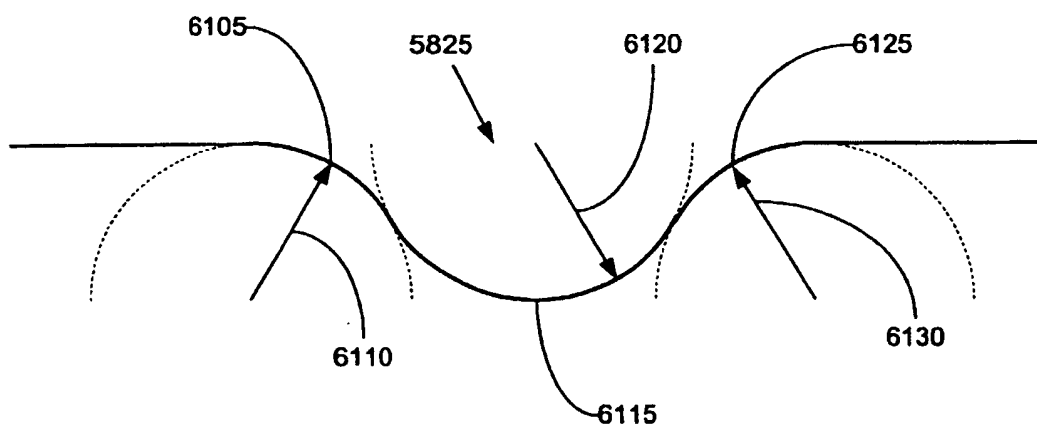


FIGURE 42

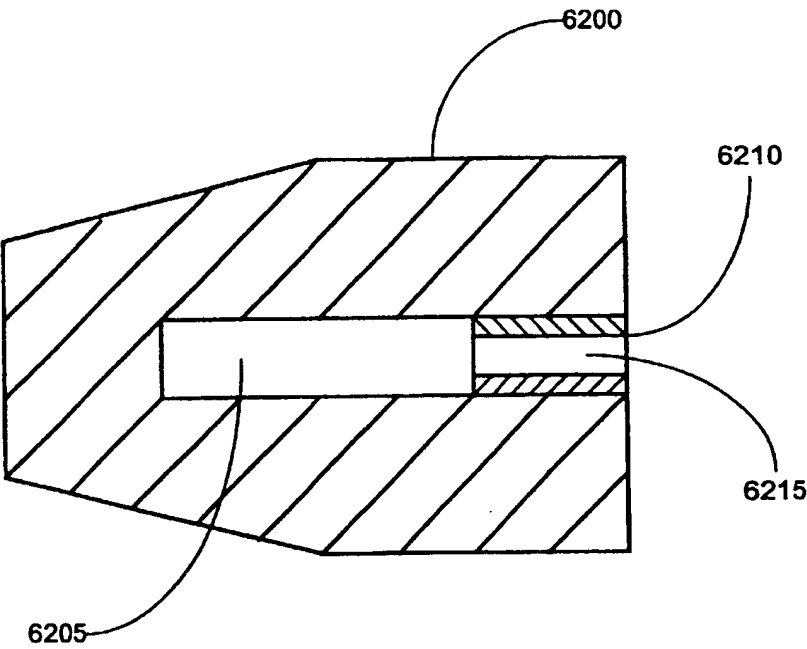


FIGURE 43

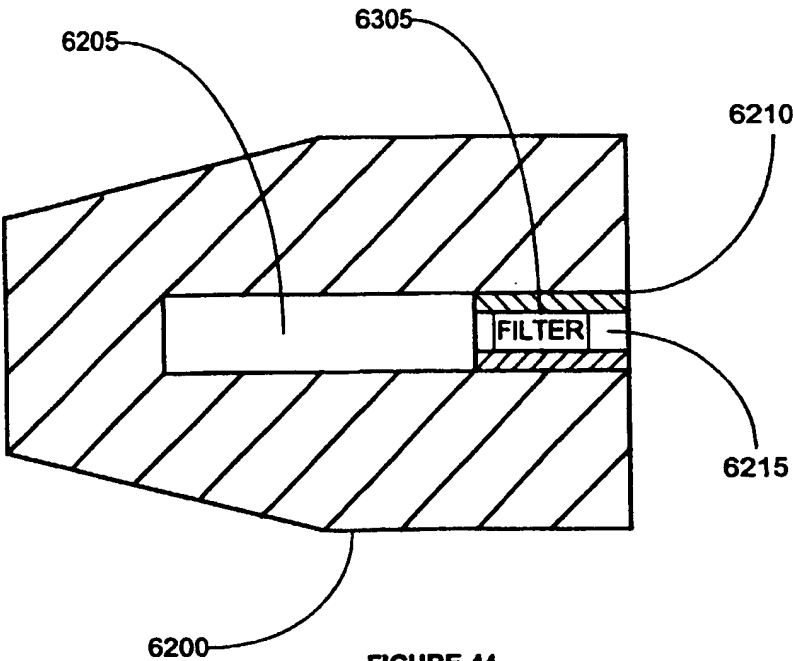


FIGURE 44

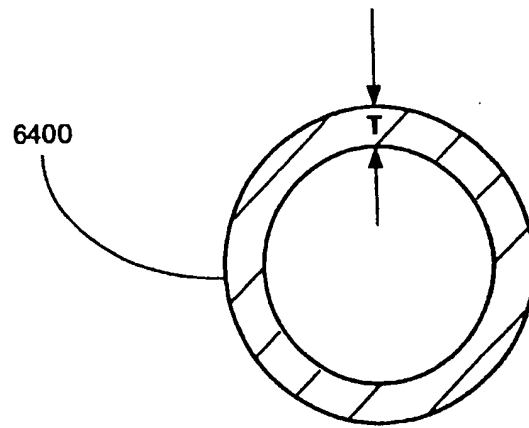


FIGURE 45

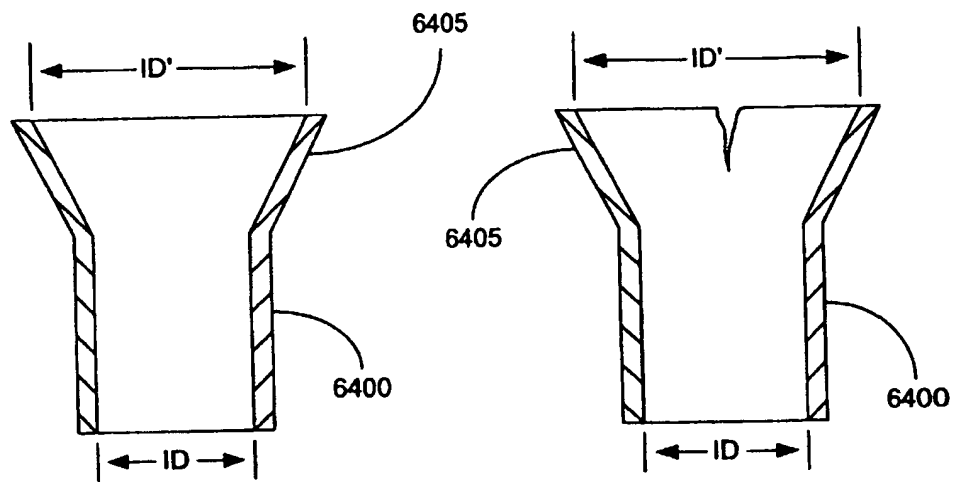


FIGURE 46

FIGURE 47

An apparatus has also been described that includes an outer tubular member, and a plurality of substantially concentric inner tubular members coupled to the interior surface of the outer tubular member by the process of expanding one or more of the inner tubular members into contact with at least a portion of the interior surface of the outer tubular member. In a preferred embodiment, the inner tubular members are expanded by extruding the inner tubular members off of a mandrel. In a preferred embodiment, the inner tubular members are expanded by the process of: placing the inner tubular members and a mandrel within the outer tubular member; and pressurizing an interior portion of the inner casing. In a preferred embodiment, during the pressurizing, the interior portion of the inner tubular member is fluidically isolated from an exterior portion of the inner tubular member. In a preferred embodiment, the interior portion of the inner tubular member is pressurized at pressures ranging from about 500 to 9,000 psi. In a preferred embodiment, the apparatus further includes one or more seals positioned in the interface between the inner tubular members and the outer tubular member. In a preferred embodiment, the inner tubular members are supported by their contact with the outer tubular member.

A wellbore casing has also been described that includes a first tubular member, and a second tubular member coupled to the first tubular member in an overlapping relationship. The inner diameter of the first tubular member is substantially equal to the inner diameter of the second tubular member. In a preferred embodiment, the first tubular member includes a first thin wall section, wherein the second tubular member includes a second thin wall section, and wherein the first thin wall section is coupled to the second thin wall section. In a preferred embodiment, first and second thin wall sections are deformed. In a preferred embodiment, the first tubular member includes a first compressible member coupled to the first thin wall section, and wherein the second tubular member includes a second compressible member coupled to the second thin wall section. In a preferred embodiment, the first thin wall section and the first compressible member are coupled to the second thin wall

tubular member 1310 is extruded off of the expandable mandrel 1305. During the extrusion process, the expandable mandrel 1305 is raised out of the expanded portion of the tubular member 1310 by the support member 1345.

5 The wiper dart 1395 is preferably placed into the fluid passage 1320 by introducing the wiper dart 1395 into the fluid passage 1320 at a surface location in a conventional manner. The wiper dart 1395 may comprise any number of conventional commercially available devices from plugging a fluid passage such as, for example, Multiple Stage Cementer latch-down plugs, Omega latch-down plugs or three wiper latch-down plug/dart modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the wiper dart 1395 comprises a three
10 wiper latch-down plug modified to latch and seal in the Multiple Stage Cementer latch down plug 1350. The three wiper latch-down plug is available from Halliburton Energy Services in Dallas, TX.

After blocking the fluid passage 1330 using the wiper plug 1330 and wiper dart
15 1395, the non hardenable fluidic material 1381 may be pumped into the interior region 1370 at pressures and flow rates ranging, for example, from approximately 0 to 5000 psi and 0 to 1,500 gallons/min in order to optimally extrude the tubular member 1310 off of the mandrel 1305. In this manner, the amount of hardenable fluidic material within the interior of the tubular member 1310 is minimized.

20 In a preferred embodiment, after blocking the fluid passage 1330, the non hardenable fluidic material 1381 is preferably pumped into the interior region 1370 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to optimally provide operating pressures to maintain the expansion process at rates sufficient to permit adjustments to be made in operating
25 parameters during the extrusion process.

For typical tubular members 1310, the extrusion of the tubular member 1310 off of the expandable mandrel 1305 will begin when the pressure of the interior region 1370 reaches, for example, approximately 500 to 9,000 psi. In a preferred embodiment, the extrusion of the tubular member 1310 off of the expandable

mandrel 1305 is a function of the tubular member diameter, wall thickness of the tubular member, geometry of the mandrel, the type of lubricant, the composition of the shoe and tubular member, and the yield strength of the tubular member. The optimum flow rate and operating pressures are preferably determined using conventional empirical methods.

During the extrusion process, the expandable mandrel 1305 may be raised out of the expanded portion of the tubular member 1310 at rates ranging, for example, from about 0 to 5 ft/sec. In a preferred embodiment, during the extrusion process, the expandable mandrel 1305 may be raised out of the expanded portion of the tubular member 1310 at rates ranging from about 0 to 2 ft/sec in order to optimally provide an efficient process, optimally permit operator adjustment of operation parameters, and ensure optimal completion of the extrusion process before curing of the material 1380.

When the upper end portion 1355 of the tubular member 1310 is extruded off of the expandable mandrel 1305, the outer surface of the upper end portion 1355 of the tubular member 1310 will preferably contact the interior surface of the lower end portion of the casing 1215 to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50 to 20,000 psi. In a preferred embodiment, the contact pressure of the overlapping joint ranges from approximately 400 to 10,000 psi in order to optimally provide contact pressure sufficient to ensure annular sealing and provide enough resistance to withstand typical tensile and compressive loads. In a particularly preferred embodiment, the sealing members 1340 will ensure an adequate fluidic and gaseous seal in the overlapping joint.

In a preferred embodiment, the operating pressure and flow rate of the non hardenable fluidic material 1381 is controllably ramped down when the expandable mandrel 1305 reaches the upper end portion 1355 of the tubular member 1310. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 1310 off of the expandable mandrel 1305 can be minimized. In a

preferred embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the mandrel 1305 has completed approximately all but about 5 feet of the extrusion process.

5 Alternatively, or in combination, a shock absorber is provided in the support member 1345 in order to absorb the shock caused by the sudden release of pressure.

Alternatively, or in combination, a mandrel catching structure is provided in the upper end portion 1355 of the tubular member 1310 in order to catch or at least decelerate the mandrel 1305.

10 Once the extrusion process is completed, the expandable mandrel 1305 is removed from the wellbore 1200. In a preferred embodiment, either before or after the removal of the expandable mandrel 1305, the integrity of the fluidic seal of the overlapping joint between the upper portion 1355 of the tubular member 1310 and the lower portion of the casing 1215 is tested using conventional methods. If the
15 fluidic seal of the overlapping joint between the upper portion 1355 of the tubular member 1310 and the lower portion of the casing 1215 is satisfactory, then the uncured portion of the material 1380 within the expanded tubular member 1310 is then removed in a conventional manner. The material 1380 within the annular region 1390 is then allowed to cure.

20 As illustrated in Fig. 11f, preferably any remaining cured material 1380 within the interior of the expanded tubular member 1310 is then removed in a conventional manner using a conventional drill string. The resulting new section of casing 1400 includes the expanded tubular member 1310 and an outer annular layer 1405 of cured material 305. The bottom portion of the apparatus 1300 comprising the shoe
25 1315 may then be removed by drilling out the shoe 1315 using conventional drilling methods.

Referring now to Figs. 12 and 13, a preferred embodiment of a wellhead system 1500 formed using one or more of the apparatus and processes described above with reference to Figs. 1-11f will be described. The wellhead system 1500 preferably

includes a conventional Christmas tree/drilling spool assembly 1505, a thick wall casing 1510, an annular body of cement 1515, an outer casing 1520, an annular body of cement 1525, an intermediate casing 1530, and an inner casing 1535.

5 The Christmas tree/drilling spool assembly 1505 may comprise any number of conventional Christmas tree/drilling spool assemblies such as, for example, the SS-15 Subsea Wellhead System, Spool Tree Subsea Production System or the Compact Wellhead System available from suppliers such as Dril-Quip, Cameron or Breda, modified in accordance with the teachings of the present disclosure. The drilling spool assembly 1505 is preferably operably coupled to the thick wall casing 1510 and/or the outer casing 1520. The assembly 1505 may be coupled to the thick wall casing 1510 and/or outer casing 1520, for example, by welding, a threaded connection or made from single stock. In a preferred embodiment, the assembly 1505 is coupled to the thick wall casing 1510 and/or outer casing 1520 by welding.

15 The thick wall casing 1510 is positioned in the upper end of a wellbore 1540. In a preferred embodiment, at least a portion of the thick wall casing 1510 extends above the surface 1545 in order to optimally provide easy access and attachment to the Christmas tree/drilling spool assembly 1505. The thick wall casing 1510 is preferably coupled to the Christmas tree/drilling spool assembly 1505, the annular body of cement 1515, and the outer casing 1520.

20 The thick wall casing 1510 may comprise any number of conventional commercially available high strength wellbore casings such as, for example, Oilfield Country Tubular Goods, titanium tubing or stainless steel tubing. In a preferred embodiment, the thick wall casing 1510 comprises Oilfield Country Tubular Goods available from various foreign and domestic steel mills. In a preferred embodiment, the thick wall casing 1510 has a yield strength of about 40,000 to 135,000 psi in order to optimally provide maximum burst, collapse, and tensile strengths. In a preferred embodiment, the thick wall casing 1510 has a failure strength in excess of about 5,000 to 20,000 psi in order to optimally provide maximum operating capacity and

resistance to degradation of capacity after being drilled through for an extended time period.

The annular body of cement 1515 provides support for the thick wall casing 1510. The annular body of cement 1515 may be provided using any number of conventional processes for forming an annular body of cement in a wellbore. The annular body of cement 1515 may comprise any number of conventional cement mixtures.

The outer casing 1520 is coupled to the thick wall casing 1510. The outer casing 1520 may be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the outer casing 1520 comprises any one of the expandable tubular members described above with reference to Figs. 1-11f.

In a preferred embodiment, the outer casing 1520 is coupled to the thick wall casing 1510 by expanding the outer casing 1520 into contact with at least a portion of the interior surface of the thick wall casing 1510 using any one of the embodiments of the processes and apparatus described above with reference to Figs. 1-11f. In an alternative embodiment, substantially all of the overlap of the outer casing 1520 with the thick wall casing 1510 contacts with the interior surface of the thick wall casing 1510.

The contact pressure of the interface between the outer casing 1520 and the thick wall casing 1510 may range, for example, from about 500 to 10,000 psi. In a preferred embodiment, the contact pressure between the outer casing 1520 and the thick wall casing 1510 ranges from about 500 to 10,000 psi in order to optimally activate the pressure activated sealing members and to ensure that the overlapping joint will optimally withstand typical extremes of tensile and compressive loads that are experienced during drilling and production operations.

As illustrated in Fig. 13, in a particularly preferred embodiment, the upper end of the outer casing 1520 includes one or more sealing members 1550 that provide a gaseous and fluidic seal between the expanded outer casing 1520 and the interior wall of the thick wall casing 1510. The sealing members 1550 may comprise any number

of conventional commercially available seals such as, for example, lead, plastic, rubber, Teflon or epoxy, modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the sealing members 1550 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in order to optimally provide an hydraulic seal and a load bearing interference fit between the tubular members. In a preferred embodiment, the contact pressure of the interface between the thick wall casing 1510 and the outer casing 1520 ranges from about 500 to 10,000 psi in order to optimally activate the sealing members 1550 and also optimally ensure that the joint will withstand the typical operating extremes of tensile and compressive loads during drilling and production operations.

In an alternative preferred embodiment, the outer casing 1520 and the thick walled casing 1510 are combined in one unitary member.

The annular body of cement 1525 provides support for the outer casing 1520. In a preferred embodiment, the annular body of cement 1525 is provided using any one of the embodiments of the apparatus and processes described above with reference to Figs. 1-11f.

The intermediate casing 1530 may be coupled to the outer casing 1520 or the thick wall casing 1510. In a preferred embodiment, the intermediate casing 1530 is coupled to the thick wall casing 1510. The intermediate casing 1530 may be fabricated from any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the intermediate casing 1530 comprises any one of the expandable tubular members described above with reference to Figs. 1-11f.

In a preferred embodiment, the intermediate casing 1530 is coupled to the thick wall casing 1510 by expanding at least a portion of the intermediate casing 1530 into contact with the interior surface of the thick wall casing 1510 using any one of the processes and apparatus described above with reference to Figs. 1-11f. In an alternative preferred embodiment, the entire length of the overlap of the intermediate casing 1530 with the thick wall casing 1510 contacts the inner surface of the thick

about 40,000 to 135,000 psi in order to optimally provide approximately the same yield properties as the tubular member 902. The tubular member 915 may comprise a plurality of tubular members coupled end to end.

5 In a preferred embodiment, the upper end portion of the tubular member 915 includes one or more sealing members for optimally providing a fluidic and/or gaseous seal with an existing section of wellbore casing.

10 In a preferred embodiment, the combined length of the tubular members 902 and 915 are limited to minimize the possibility of buckling. For typical tubular member materials, the combined length of the tubular members 902 and 915 are limited to between about 40 to 20,000 feet in length.

The lower portion 914 of the tubular member 902 is preferably coupled to the shoe 908 by a threaded connection 968. The intermediate portion 912 of the tubular member 902 preferably is placed in intimate sliding contact with the mandrel 906.

15 The tubular member 902 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steels, titanium or stainless steels. In a preferred embodiment, the tubular member 902 is fabricated from oilfield tubulars in order to optimally provide approximately the same mechanical properties as the tubular member 915. In a particularly preferred embodiment, the tubular member 902 has a plastic yield point ranging from
20 about 40,000 to 135,000 psi in order to optimally provide approximately the same yield properties as the tubular member 915.

25 The wall thickness of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 may range, for example, from about 1/16 to 1.5 inches. In a preferred embodiment, the wall thickness of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 range from about 1/8 to 1.25 in order to optimally provide wall thickness that are about the same as the tubular member 915. In a preferred embodiment, the wall thickness of the lower portion 914 is less than or equal to the wall thickness of the upper portion 910 in order to optimally provide a geometry that will fit into tight clearances downhole.

The outer diameter of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 may range, for example, from about 1.05 to 48 inches. In a preferred embodiment, the outer diameter of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 range from about 3 ½ to 19 inches in order to optimally provide the ability to expand the most commonly used oilfield tubulars.

The length of the tubular member 902 is preferably limited to between about 2 to 5 feet in order to optimally provide enough length to contain the mandrel 906 and a body of lubricant.

The tubular member 902 may comprise any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the tubular member 902 comprises Oilfield Country Tubular Goods available from various U.S. steel mills. The tubular member 915 may comprise any number of conventional commercially available tubular members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the tubular member 915 comprises Oilfield Country Tubular Goods available from various U.S. steel mills.

The various elements of the tubular member 902 may be coupled using any number of conventional process such as, for example, threaded connections, welding or machined from one piece. In a preferred embodiment, the various elements of the tubular member 902 are coupled using welding. The tubular member 902 may comprise a plurality of tubular elements that are coupled end to end. The various elements of the tubular member 915 may be coupled using any number of conventional process such as, for example, threaded connections, welding or machined from one piece. In a preferred embodiment, the various elements of the tubular member 915 are coupled using welding. The tubular member 915 may comprise a plurality of tubular elements that are coupled end to end. The tubular members 902 and 915 may be coupled using any number of conventional process such as, for example, threaded connections, welding or machined from one piece.

The support member 904 preferably includes an innerstring adapter 916, a fluid passage 918, an upper guide 920, and a coupling 922. During operation of the apparatus 900, the support member 904 preferably supports the apparatus 900 during movement of the apparatus 900 within a wellbore. The support member 904 preferably has a substantially annular cross-section.

The support member 904 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel, coiled tubing or stainless steel. In a preferred embodiment, the support member 904 is fabricated from low alloy steel in order to optimally provide high yield strength.

The innerstring adaptor 916 preferably is coupled to and supported by a conventional drill string support from a surface location. The innerstring adaptor 916 may be coupled to a conventional drill string support 971 by a threaded connection 970.

The fluid passage 918 is preferably used to convey fluids and other materials to and from the apparatus 900. In a preferred embodiment, the fluid passage 918 is fluidically coupled to the fluid passage 952. In a preferred embodiment, the fluid passage 918 is used to convey hardenable fluidic sealing materials to and from the apparatus 900. In a particularly preferred embodiment, the fluid passage 918 may include one or more pressure relief passages (not illustrated) to release fluid pressure during positioning of the apparatus 900 within a wellbore. In a preferred embodiment, the fluid passage 918 is positioned along a longitudinal centerline of the apparatus 900. In a preferred embodiment, the fluid passage 918 is selected to permit the conveyance of hardenable fluidic materials at operating pressures ranging from about 0 to 9,000 psi.

The upper guide 920 is coupled to an upper portion of the support member 904. The upper guide 920 preferably is adapted to center the support member 904 within the tubular member 915. The upper guide 920 may comprise any number of conventional guide members modified in accordance with the teachings of the present

disclosure. In a preferred embodiment, the upper guide 920 comprises an innerstring adapter available from Halliburton Energy Services in Dallas, TX order to optimally guide the apparatus 900 within the tubular member 915.

5 The coupling 922 couples the support member 904 to the mandrel 906. The coupling 922 preferably comprises a conventional threaded connection.

The various elements of the support member 904 may be coupled using any number of conventional processes such as, for example, welding, threaded connections or machined from one piece. In a preferred embodiment, the various elements of the support member 904 are coupled using threaded connections.

10 The mandrel 906 preferably includes a retainer 924, a rubber cup 926, an expansion cone 928, a lower cone retainer 930, a body of cement 932, a lower guide 934, an extension sleeve 936, a spacer 938, a housing 940, a sealing sleeve 942, an upper cone retainer 944, a lubricator mandrel 946, a lubricator sleeve 948, a guide 950, and a fluid passage 952.

15 The retainer 924 is coupled to the lubricator mandrel 946, lubricator sleeve 948, and the rubber cup 926. The retainer 924 couples the rubber cup 926 to the lubricator sleeve 948. The retainer 924 preferably has a substantially annular cross-section. The retainer 924 may comprise any number of conventional commercially available retainers such as, for example, slotted spring pins or roll pin.

20 The rubber cup 926 is coupled to the retainer 924, the lubricator mandrel 946, and the lubricator sleeve 948. The rubber cup 926 prevents the entry of foreign materials into the interior region 972 of the tubular member 902 below the rubber cup 926. The rubber cup 926 may comprise any number of conventional commercially available rubber cups such as, for example, TP cups or Selective
25 Injection Packer (SIP) cup. In a preferred embodiment, the rubber cup 926 comprises a SIP cup available from Halliburton Energy Services in Dallas, TX in order to optimally block foreign materials.

In a particularly preferred embodiment, a body of lubricant is further provided in the interior region 972 of the tubular member 902 in order to lubricate the

interface between the exterior surface of the mandrel 902 and the interior surface of the tubular members 902 and 915. The lubricant may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antiseize (3100). In
5 a preferred embodiment, the lubricant comprises Climax 1500 Antiseize (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide lubrication to facilitate the extrusion process.

The expansion cone 928 is coupled to the lower cone retainer 930, the body of cement 932, the lower guide 934, the extension sleeve 936, the housing 940, and the
10 upper cone retainer 944. In a preferred embodiment, during operation of the apparatus 900, the tubular members 902 and 915 are extruded off of the outer surface of the expansion cone 928. In a preferred embodiment, axial movement of the expansion cone 928 is prevented by the lower cone retainer 930, housing 940 and the upper cone retainer 944. Inner radial movement of the expansion cone 928 is
15 prevented by the body of cement 932, the housing 940, and the upper cone retainer 944.

The expansion cone 928 preferably has a substantially annular cross section. The outside diameter of the expansion cone 928 is preferably tapered to provide a cone shape. The wall thickness of the expansion cone 928 may range, for example,
20 from about 0.125 to 3 inches. In a preferred embodiment, the wall thickness of the expansion cone 928 ranges from about 0.25 to 0.75 inches in order to optimally provide adequate compressive strength with minimal material. The maximum and minimum outside diameters of the expansion cone 928 may range, for example, from about 1 to 47 inches. In a preferred embodiment, the maximum and minimum
25 outside diameters of the expansion cone 928 range from about 3.5 to 19 in order to optimally provide expansion of generally available oilfield tubulars

The expansion cone 928 may be fabricated from any number of conventional commercially available materials such as, for example, ceramic, tool steel, titanium or low alloy steel. In a preferred embodiment, the expansion cone 928 is fabricated

from tool steel in order to optimally provide high strength and abrasion resistance. The surface hardness of the outer surface of the expansion cone 928 may range, for example, from about 50 Rockwell C to 70 Rockwell C. In a preferred embodiment, the surface hardness of the outer surface of the expansion cone 928 ranges from about 58 Rockwell C to 62 Rockwell C in order to optimally provide high yield strength. In a preferred embodiment, the expansion cone 928 is heat treated to optimally provide a hard outer surface and a resilient interior body in order to optimally provide abrasion resistance and fracture toughness.

10 The lower cone retainer 930 is coupled to the expansion cone 928 and the housing 940. In a preferred embodiment, axial movement of the expansion cone 928 is prevented by the lower cone retainer 930. Preferably, the lower cone retainer 930 has a substantially annular cross-section.

15 The lower cone retainer 930 may be fabricated from any number of conventional commercially available materials such as, for example, ceramic, tool steel, titanium or low alloy steel. In a preferred embodiment, the lower cone retainer 930 is fabricated from tool steel in order to optimally provide high strength and abrasion resistance. The surface hardness of the outer surface of the lower cone retainer 930 may range, for example, from about 50 Rockwell C to 70 Rockwell C. In a preferred embodiment, the surface hardness of the outer surface of the lower cone retainer 930 ranges from about 58 Rockwell C to 62 Rockwell C in order to optimally provide high yield strength. In a preferred embodiment, the lower cone retainer 930 is heat treated to optimally provide a hard outer surface and a resilient interior body in order to optimally provide abrasion resistance and fracture toughness.

25 In a preferred embodiment, the lower cone retainer 930 and the expansion cone 928 are formed as an integral one-piece element in order reduce the number of components and increase the overall strength of the apparatus. The outer surface of the lower cone retainer 930 preferably mates with the inner surfaces of the tubular members 902 and 915.

The body of cement 932 is positioned within the interior of the mandrel 906. The body of cement 932 provides an inner bearing structure for the mandrel 906. The body of cement 932 further may be easily drilled out using a conventional drill device. In this manner, the mandrel 906 may be easily removed using a conventional drilling device.

The body of cement 932 may comprise any number of conventional commercially available cement compounds. Alternatively, aluminum, cast iron or some other drillable metallic, composite, or aggregate material may be substituted for cement. The body of cement 932 preferably has a substantially annular cross-section.

The lower guide 934 is coupled to the extension sleeve 936 and housing 940. During operation of the apparatus 900, the lower guide 934 preferably helps guide the movement of the mandrel 906 within the tubular member 902. The lower guide 934 preferably has a substantially annular cross-section.

The lower guide 934 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel or stainless steel. In a preferred embodiment, the lower guide 934 is fabricated from low alloy steel in order to optimally provide high yield strength. The outer surface of the lower guide 934 preferably mates with the inner surface of the tubular member 902 to provide a sliding fit.

The extension sleeve 936 is coupled to the lower guide 934 and the housing 940. During operation of the apparatus 900, the extension sleeve 936 preferably helps guide the movement of the mandrel 906 within the tubular member 902. The extension sleeve 936 preferably has a substantially annular cross-section.

The extension sleeve 936 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel or stainless steel. In a preferred embodiment, the extension sleeve 936 is fabricated from low alloy steel in order to optimally provide high yield strength. The outer surface of the extension sleeve 936 preferably mates with the inner surface of the tubular member 902 to provide a sliding fit. In a preferred embodiment, the

extension sleeve 936 and the lower guide 934 are formed as an integral one-piece element in order to minimize the number of components and increase the strength of the apparatus.

5 The spacer 938 is coupled to the sealing sleeve 942. The spacer 938 preferably includes the fluid passage 952 and is adapted to mate with the extension tube 960 of the shoe 908. In this manner, a plug or dart can be conveyed from the surface through the fluid passages 918 and 952 into the fluid passage 962. Preferably, the spacer 938 has a substantially annular cross-section.

10 The spacer 938 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the spacer 938 is fabricated from aluminum in order to optimally provide drillability. The end of the spacer 938 preferably mates with the end of the extension tube 960. In a preferred embodiment, the spacer 938 and the sealing sleeve 942 are formed as an integral one-piece element in order to reduce the
15 number of components and increase the strength of the apparatus.

The housing 940 is coupled to the lower guide 934, extension sleeve 936, expansion cone 928, body of cement 932, and lower cone retainer 930. During operation of the apparatus 900, the housing 940 preferably prevents inner radial motion of the expansion cone 928. Preferably, the housing 940 has a substantially
20 annular cross-section.

The housing 940 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel or stainless steel. In a preferred embodiment, the housing 940 is fabricated from low alloy steel in order to optimally provide high yield strength. In a preferred
25 embodiment, the lower guide 934, extension sleeve 936 and housing 940 are formed as an integral one-piece element in order to minimize the number of components and increase the strength of the apparatus.

In a particularly preferred embodiment, the interior surface of the housing 940 includes one or more protrusions to facilitate the connection between the housing 940 and the body of cement 932.

5 The sealing sleeve 942 is coupled to the support member 904, the body of cement 932, the spacer 938, and the upper cone retainer 944. During operation of the apparatus, the sealing sleeve 942 preferably provides support for the mandrel 906. The sealing sleeve 942 is preferably coupled to the support member 904 using the coupling 922. Preferably, the sealing sleeve 942 has a substantially annular cross-section.

10 The sealing sleeve 942 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the sealing sleeve 942 is fabricated from aluminum in order to optimally provide drillability of the sealing sleeve 942.

15 In a particularly preferred embodiment, the outer surface of the sealing sleeve 942 includes one or more protrusions to facilitate the connection between the sealing sleeve 942 and the body of cement 932.

In a particularly preferred embodiment, the spacer 938 and the sealing sleeve 942 are integrally formed as a one-piece element in order to minimize the number of components.

20 The upper cone retainer 944 is coupled to the expansion cone 928, the sealing sleeve 942, and the body of cement 932. During operation of the apparatus 900, the upper cone retainer 944 preferably prevents axial motion of the expansion cone 928. Preferably, the upper cone retainer 944 has a substantially annular cross-section.

25 The upper cone retainer 944 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the upper cone retainer 944 is fabricated from aluminum in order to optimally provide drillability of the upper cone retainer 944.

In a particularly preferred embodiment, the upper cone retainer 944 has a cross-sectional shape designed to provide increased rigidity. In a particularly preferred embodiment, the upper cone retainer 944 has a cross-sectional shape that is substantially I-shaped to provide increased rigidity and minimize the amount of material that would have to be drilled out.

The lubricator mandrel 946 is coupled to the retainer 924, the rubber cup 926, the upper cone retainer 944, the lubricator sleeve 948, and the guide 950. During operation of the apparatus 900, the lubricator mandrel 946 preferably contains the body of lubricant in the annular region 972 for lubricating the interface between the mandrel 906 and the tubular member 902. Preferably, the lubricator mandrel 946 has a substantially annular cross-section.

The lubricator mandrel 946 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the lubricator mandrel 946 is fabricated from aluminum in order to optimally provide drillability of the lubricator mandrel 946.

The lubricator sleeve 948 is coupled to the lubricator mandrel 946, the retainer 924, the rubber cup 926, the upper cone retainer 944, the lubricator sleeve 948, and the guide 950. During operation of the apparatus 900, the lubricator sleeve 948 preferably supports the rubber cup 926. Preferably, the lubricator sleeve 948 has a substantially annular cross-section.

The lubricator sleeve 948 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the lubricator sleeve 948 is fabricated from aluminum in order to optimally provide drillability of the lubricator sleeve 948.

As illustrated in Fig. 9c, the lubricator sleeve 948 is supported by the lubricator mandrel 946. The lubricator sleeve 948 in turn supports the rubber cup 926. The retainer 924 couples the rubber cup 926 to the lubricator sleeve 948. In a preferred embodiment, seals 949a and 949b are provided between the lubricator mandrel 946,

lubricator sleeve 948, and rubber cup 926 in order to optimally seal off the interior region 972 of the tubular member 902.

5 The guide 950 is coupled to the lubricator mandrel 946, the retainer 924, and the lubricator sleeve 948. During operation of the apparatus 900, the guide 950 preferably guides the apparatus on the support member 904. Preferably, the guide 950 has a substantially annular cross-section.

10 The guide 950 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the guide 950 is fabricated from aluminum order to optimally provide drillability of the guide 950.

15 The fluid passage 952 is coupled to the mandrel 906. During operation of the apparatus, the fluid passage 952 preferably conveys hardenable fluidic materials. In a preferred embodiment, the fluid passage 952 is positioned about the centerline of the apparatus 900. In a particularly preferred embodiment, the fluid passage 952 is adapted to convey hardenable fluidic materials at pressures and flow rate ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/min in order to optimally provide pressures and flow rates to displace and circulate fluids during the installation of the apparatus 900.

20 The various elements of the mandrel 906 may be coupled using any number of conventional process such as, for example, threaded connections, welded connections or cementing. In a preferred embodiment, the various elements of the mandrel 906 are coupled using threaded connections and cementing.

25 The shoe 908 preferably includes a housing 954, a body of cement 956, a sealing sleeve 958, an extension tube 960, a fluid passage 962, and one or more outlet jets 964.

The housing 954 is coupled to the body of cement 956 and the lower portion 914 of the tubular member 902. During operation of the apparatus 900, the housing 954 preferably couples the lower portion of the tubular member 902 to the shoe 908

to facilitate the extrusion and positioning of the tubular member 902. Preferably, the housing 954 has a substantially annular cross-section.

5 The housing 954 may be fabricated from any number of conventional commercially available materials such as, for example, steel or aluminum. In a preferred embodiment, the housing 954 is fabricated from aluminum in order to optimally provide drillability of the housing 954.

In a particularly preferred embodiment, the interior surface of the housing 954 includes one or more protrusions to facilitate the connection between the body of cement 956 and the housing 954.

10 The body of cement 956 is coupled to the housing 954, and the sealing sleeve 958. In a preferred embodiment, the composition of the body of cement 956 is selected to permit the body of cement to be easily drilled out using conventional drilling machines and processes.

15 The composition of the body of cement 956 may include any number of conventional cement compositions. In an alternative embodiment, a drillable material such as, for example, aluminum or iron may be substituted for the body of cement 956.

20 The sealing sleeve 958 is coupled to the body of cement 956, the extension tube 960, the fluid passage 962, and one or more outlet jets 964. During operation of the apparatus 900, the sealing sleeve 958 preferably is adapted to convey a hardenable fluidic material from the fluid passage 952 into the fluid passage 962 and then into the outlet jets 964 in order to inject the hardenable fluidic material into an annular region external to the tubular member 902. In a preferred embodiment, during operation of the apparatus 900, the sealing sleeve 958 further includes an inlet geometry that permits a conventional plug or dart 974 to become lodged in the inlet of the sealing sleeve 958. In this manner, the fluid passage 962 may be blocked thereby fluidically isolating the interior region 966 of the tubular member 902.

25 In a preferred embodiment, the sealing sleeve 958 has a substantially annular cross-section. The sealing sleeve 958 may be fabricated from any number of

conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the sealing sleeve 958 is fabricated from aluminum in order to optimally provide drillability of the sealing sleeve 958.

5 The extension tube 960 is coupled to the sealing sleeve 958, the fluid passage 962, and one or more outlet jets 964. During operation of the apparatus 900, the extension tube 960 preferably is adapted to convey a hardenable fluidic material from the fluid passage 952 into the fluid passage 962 and then into the outlet jets 964 in order to inject the hardenable fluidic material into an annular region external to the tubular member 902. In a preferred embodiment, during operation of the apparatus 10 900, the sealing sleeve 960 further includes an inlet geometry that permits a conventional plug or dart 974 to become lodged in the inlet of the sealing sleeve 958. In this manner, the fluid passage 962 is blocked thereby fluidically isolating the interior region 966 of the tubular member 902. In a preferred embodiment, one end of the extension tube 960 mates with one end of the spacer 938 in order to optimally 15 facilitate the transfer of material between the two.

In a preferred embodiment, the extension tube 960 has a substantially annular cross-section. The extension tube 960 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the extension tube 960 is fabricated from 20 aluminum in order to optimally provide drillability of the extension tube 960.

The fluid passage 962 is coupled to the sealing sleeve 958, the extension tube 960, and one or more outlet jets 964. During operation of the apparatus 900, the fluid passage 962 is preferably conveys hardenable fluidic materials. In a preferred embodiment, the fluid passage 962 is positioned about the centerline of the apparatus 25 900. In a particularly preferred embodiment, the fluid passage 962 is adapted to convey hardenable fluidic materials at pressures and flow rate ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/min in order to optimally provide fluids at operationally efficient rates.

The outlet jets 964 are coupled to the sealing sleeve 958, the extension tube 960, and the fluid passage 962. During operation of the apparatus 900, the outlet jets 964 preferably convey hardenable fluidic material from the fluid passage 962 to the region exterior of the apparatus 900. In a preferred embodiment, the shoe 908
5 includes a plurality of outlet jets 964.

In a preferred embodiment, the outlet jets 964 comprise passages drilled in the housing 954 and the body of cement 956 in order to simplify the construction of the apparatus 900.

The various elements of the shoe 908 may be coupled using any number of
10 conventional process such as, for example, threaded connections, cement or machined from one piece of material. In a preferred embodiment, the various elements of the shoe 908 are coupled using cement.

In a preferred embodiment, the assembly 900 is operated substantially as described above with reference to Figs. 1-8 to create a new section of casing in a
15 wellbore or to repair a wellbore casing or pipeline.

In particular, in order to extend a wellbore into a subterranean formation, a drill string is used in a well known manner to drill out material from the subterranean formation to form a new section.

The apparatus 900 for forming a wellbore casing in a subterranean formation
20 is then positioned in the new section of the wellbore. In a particularly preferred embodiment, the apparatus 900 includes the tubular member 915. In a preferred embodiment, a hardenable fluidic sealing hardenable fluidic sealing material is then pumped from a surface location into the fluid passage 918. The hardenable fluidic sealing material then passes from the fluid passage 918 into the interior region 966
25 of the tubular member 902 below the mandrel 906. The hardenable fluidic sealing material then passes from the interior region 966 into the fluid passage 962. The hardenable fluidic sealing material then exits the apparatus 900 via the outlet jets 964 and fills an annular region between the exterior of the tubular member 902 and the interior wall of the new section of the wellbore. Continued pumping of the

hardenable fluidic sealing material causes the material to fill up at least a portion of the annular region.

5 The hardenable fluidic sealing material is preferably pumped into the annular region at pressures and flow rates ranging, for example, from about 0 to 5,000 psi and 0 to 1,500 gallons/min, respectively. In a preferred embodiment, the hardenable fluidic sealing material is pumped into the annular region at pressures and flow rates that are designed for the specific wellbore section in order to optimize the displacement of the hardenable fluidic sealing material while not creating high enough circulating pressures such that circulation might be lost and that could cause the wellbore to collapse. The optimum pressures and flow rates are preferably determined using conventional empirical methods.

10 The hardenable fluidic sealing material may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In a preferred embodiment, the hardenable fluidic sealing material comprises blended cements designed specifically for the well section being lined available from Halliburton Energy Services in Dallas, TX in order to optimally provide support for the new tubular member while also maintaining optimal flow characteristics so as to minimize operational difficulties during the displacement of the cement in the annular region. The optimum composition of the blended cements is preferably determined using conventional empirical methods.

20 The annular region preferably is filled with the hardenable fluidic sealing material in sufficient quantities to ensure that, upon radial expansion of the tubular member 902, the annular region of the new section of the wellbore will be filled with hardenable material.

25 Once the annular region has been adequately filled with hardenable fluidic sealing material, a plug or dart 974, or other similar device, preferably is introduced into the fluid passage 962 thereby fluidically isolating the interior region 966 of the tubular member 902 from the external annular region. In a preferred embodiment, a non hardenable fluidic material is then pumped into the interior region 966 causing

the interior region 966 to pressurize. In a particularly preferred embodiment, the plug or dart 974, or other similar device, preferably is introduced into the fluid passage 962 by introducing the plug or dart 974, or other similar device into the non hardenable fluidic material. In this manner, the amount of cured material within the interior of the tubular members 902 and 915 is minimized.

Once the interior region 966 becomes sufficiently pressurized, the tubular members 902 and 915 are extruded off of the mandrel 906. The mandrel 906 may be fixed or it may be expandable. During the extrusion process, the mandrel 906 is raised out of the expanded portions of the tubular members 902 and 915 using the support member 904. During this extrusion process, the shoe 908 is preferably substantially stationary.

The plug or dart 974 is preferably placed into the fluid passage 962 by introducing the plug or dart 974 into the fluid passage 918 at a surface location in a conventional manner. The plug or dart 974 may comprise any number of conventional commercially available devices for plugging a fluid passage such as, for example, Multiple Stage Cementer (MSC) latch-down plug, Omega latch-down plug or three-wiper latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the plug or dart 974 comprises a MSC latch-down plug available from Halliburton Energy Services in Dallas, TX.

After placement of the plug or dart 974 in the fluid passage 962, the non hardenable fluidic material is preferably pumped into the interior region 966 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to optimally extrude the tubular members 902 and 915 off of the mandrel 906.

For typical tubular members 902 and 915, the extrusion of the tubular members 902 and 915 off of the expandable mandrel will begin when the pressure of the interior region 966 reaches approximately 500 to 9,000 psi. In a preferred embodiment, the extrusion of the tubular members 902 and 915 off of the mandrel

906 begins when the pressure of the interior region 966 reaches approximately 1,200 to 8,500 psi with a flow rate of about 40 to 1250 gallons/minute.

During the extrusion process, the mandrel 906 may be raised out of the expanded portions of the tubular members 902 and 915 at rates ranging, for example, from about 0 to 5 ft/sec. In a preferred embodiment, during the extrusion process, the mandrel 906 is raised out of the expanded portions of the tubular members 902 and 915 at rates ranging from about 0 to 2 ft/sec in order to optimally provide pulling speed fast enough to permit efficient operation and permit full expansion of the tubular members 902 and 915 prior to curing of the hardenable fluidic sealing material; but not so fast that timely adjustment of operating parameters during operation is prevented.

When the upper end portion of the tubular member 915 is extruded off of the mandrel 906, the outer surface of the upper end portion of the tubular member 915 will preferably contact the interior surface of the lower end portion of the existing casing to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50 to 20,000 psi. In a preferred embodiment, the contact pressure of the overlapping joint between the upper end of the tubular member 915 and the existing section of wellbore casing ranges from approximately 400 to 10,000 psi in order to optimally provide contact pressure to activate the sealing members and provide optimal resistance such that the tubular member 915 and existing wellbore casing will carry typical tensile and compressive loads.

In a preferred embodiment, the operating pressure and flow rate of the non hardenable fluidic material will be controllably ramped down when the mandrel 906 reaches the upper end portion of the tubular member 915. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 915 off of the expandable mandrel 906 can be minimized. In a preferred embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about

10% during the end of the extrusion process beginning when the mandrel 906 has completed approximately all but about the last 5 feet of the extrusion process.

In an alternative preferred embodiment, the operating pressure and/or flow rate of the hardenable fluidic sealing material and/or the non hardenable fluidic material are controlled during all phases of the operation of the apparatus 900 to minimize shock.

Alternatively, or in combination, a shock absorber is provided in the support member 904 in order to absorb the shock caused by the sudden release of pressure.

Alternatively, or in combination, a mandrel catching structure is provided above the support member 904 in order to catch or at least decelerate the mandrel 906.

Once the extrusion process is completed, the mandrel 906 is removed from the wellbore. In a preferred embodiment, either before or after the removal of the mandrel 906, the integrity of the fluidic seal of the overlapping joint between the upper portion of the tubular member 915 and the lower portion of the existing casing is tested using conventional methods. If the fluidic seal of the overlapping joint between the upper portion of the tubular member 915 and the lower portion of the existing casing is satisfactory, then the uncured portion of any of the hardenable fluidic sealing material within the expanded tubular member 915 is then removed in a conventional manner. The hardenable fluidic sealing material within the annular region between the expanded tubular member 915 and the existing casing and new section of wellbore is then allowed to cure.

Preferably any remaining cured hardenable fluidic sealing material within the interior of the expanded tubular members 902 and 915 is then removed in a conventional manner using a conventional drill string. The resulting new section of casing preferably includes the expanded tubular members 902 and 915 and an outer annular layer of cured hardenable fluidic sealing material. The bottom portion of the apparatus 900 comprising the shoe 908 may then be removed by drilling out the shoe 908 using conventional drilling methods.

In an alternative embodiment, during the extrusion process, it may be necessary to remove the entire apparatus 900 from the interior of the wellbore due to a malfunction. In this circumstance, a conventional drill string is used to drill out the interior sections of the apparatus 900 in order to facilitate the removal of the remaining sections. In a preferred embodiment, the interior elements of the apparatus 900 are fabricated from materials such as, for example, cement and aluminum, that permit a conventional drill string to be employed to drill out the interior components.

In particular, in a preferred embodiment, the composition of the interior sections of the mandrel 906 and shoe 908, including one or more of the body of cement 932, the spacer 938, the sealing sleeve 942, the upper cone retainer 944, the lubricator mandrel 946, the lubricator sleeve 948, the guide 950, the housing 954, the body of cement 956, the sealing sleeve 958, and the extension tube 960, are selected to permit at least some of these components to be drilled out using conventional drilling methods and apparatus. In this manner, in the event of a malfunction downhole, the apparatus 900 may be easily removed from the wellbore.

Referring now to Figs. 10a, 10b, 10c, 10d, 10e, 10f, and 10g a method and apparatus for creating a tie-back liner in a wellbore will now be described. As illustrated in Fig. 10a, a wellbore 1000 positioned in a subterranean formation 1002 includes a first casing 1004 and a second casing 1006.

The first casing 1004 preferably includes a tubular liner 1008 and a cement annulus 1010. The second casing 1006 preferably includes a tubular liner 1012 and a cement annulus 1014. In a preferred embodiment, the second casing 1006 is formed by expanding a tubular member substantially as described above with reference to Figs. 1-9c or below with reference to Figs. 11a-11f.

In a particularly preferred embodiment, an upper portion of the tubular liner 1012 overlaps with a lower portion of the tubular liner 1008. In a particularly preferred embodiment, an outer surface of the upper portion of the tubular liner 1012

includes one or more sealing members 1016 for providing a fluidic seal between the tubular liners 1008 and 1012.

Referring to Fig. 10b, in order to create a tie-back liner that extends from the overlap between the first and second casings, 1004 and 1006, an apparatus 1100 is preferably provided that includes an expandable mandrel or pig 1105, a tubular member 1110, a shoe 1115, one or more cup seals 1120, a fluid passage 1130, a fluid passage 1135, one or more fluid passages 1140, seals 1145, and a support member 1150.

The expandable mandrel or pig 1105 is coupled to and supported by the support member 1150. The expandable mandrel 1105 is preferably adapted to controllably expand in a radial direction. The expandable mandrel 1105 may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the expandable mandrel 1105 comprises a hydraulic expansion tool substantially as disclosed in U.S. Pat. No. 5,348,095, the disclosure of which is incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The tubular member 1110 is coupled to and supported by the expandable mandrel 1105. The tubular member 1105 is expanded in the radial direction and extruded off of the expandable mandrel 1105. The tubular member 1110 may be fabricated from any number of materials such as, for example, Oilfield Country Tubular Goods, 13 chromium tubing or plastic piping. In a preferred embodiment, the tubular member 1110 is fabricated from Oilfield Country Tubular Goods.

The inner and outer diameters of the tubular member 1110 may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. In a preferred embodiment, the inner and outer diameters of the tubular member 1110 range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide coverage for typical oilfield casing sizes. The tubular member 1110 preferably comprises a solid member.

In a preferred embodiment, the upper end portion of the tubular member 1110 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 1105 when it completes the extrusion of tubular member 1110. In a preferred embodiment, the length of the tubular member 1110 is limited to minimize the possibility of buckling. For typical tubular member 1110 materials, the length of the tubular member 1110 is preferably limited to between about 40 to 20,000 feet in length.

The shoe 1115 is coupled to the expandable mandrel 1105 and the tubular member 1110. The shoe 1115 includes the fluid passage 1135. The shoe 1115 may comprise any number of conventional commercially available shoes such as, for example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 1115 comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug with side ports radiating off of the exit flow port available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 1100 to the overlap between the tubular member 1100 and the casing 1012, optimally fluidically isolate the interior of the tubular member 1100 after the latch down plug has seated, and optimally permit drilling out of the shoe 1115 after completion of the expansion and cementing operations.

In a preferred embodiment, the shoe 1115 includes one or more side outlet ports 1140 in fluidic communication with the fluid passage 1135. In this manner, the shoe 1115 injects hardenable fluidic sealing material into the region outside the shoe 1115 and tubular member 1110. In a preferred embodiment, the shoe 1115 includes one or more of the fluid passages 1140 each having an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passages 1140 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 1130.

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region exterior to the tubular member 1105. This permits the interior region of the tubular member 1110 below the expandable mandrel 1105 to be pressurized.

The fluid passages 1140 are preferably positioned along the periphery of the shoe 1115. The fluid passages 1140 are preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member 1110 and the tubular liner 1008 with fluidic materials. In a preferred embodiment, the fluid passages 1140 include an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passages 1140 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 1130. In a preferred embodiment, the apparatus 1100 includes a plurality of fluid passage 1140.

In an alternative embodiment, the base of the shoe 1115 includes a single inlet passage coupled to the fluid passages 1140 that is adapted to receive a plug, or other similar device, to permit the interior region of the tubular member 1110 to be fluidically isolated from the exterior of the tubular member 1110.

The seals 1145 are coupled to and supported by a lower end portion of the tubular member 1110. The seals 1145 are further positioned on an outer surface of the lower end portion of the tubular member 1110. The seals 1145 permit the overlapping joint between the upper end portion of the casing 1012 and the lower end portion of the tubular member 1110 to be fluidically sealed.

The seals 1145 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the seals 1145 comprise seals molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a hydraulic seal in the overlapping joint and optimally provide load carrying capacity to withstand the range of typical tensile and compressive loads.

In a preferred embodiment, the seals 1145 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 1110 from the tubular liner 1008. In a preferred embodiment, the frictional force provided by the seals 1145 ranges from about 1,000 to 1,000,000 lbf in tension and compression in order to optimally support the expanded tubular member 1110.

The support member 1150 is coupled to the expandable mandrel 1105, tubular member 1110, shoe 1115, and seal 1120. The support member 1150 preferably comprises an annular member having sufficient strength to carry the apparatus 1100 into the wellbore 1000. In a preferred embodiment, the support member 1150 further includes one or more conventional centralizers (not illustrated) to help stabilize the tubular member 1110.

In a preferred embodiment, a quantity of lubricant 1150 is provided in the annular region above the expandable mandrel 1105 within the interior of the tubular member 1110. In this manner, the extrusion of the tubular member 1110 off of the expandable mandrel 1105 is facilitated. The lubricant 1150 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants or Climax 1500 Antiseize (3100). In a preferred embodiment, the lubricant 1150 comprises Climax 1500 Antiseize (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide lubrication for the extrusion process.

In a preferred embodiment, the support member 1150 is thoroughly cleaned prior to assembly to the remaining portions of the apparatus 1100. In this manner, the introduction of foreign material into the apparatus 1100 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 1100 and to ensure that no foreign material interferes with the expansion mandrel 1105 during the extrusion process.

In a particularly preferred embodiment, the apparatus 1100 includes a packer 1155 coupled to the bottom section of the shoe 1115 for fluidically isolating the region of the wellbore 1000 below the apparatus 1100. In this manner, fluidic materials are

prevented from entering the region of the wellbore 1000 below the apparatus 1100. The packer 1155 may comprise any number of conventional commercially available packers such as, for example, EZ Drill Packer, EZ SV Packer or a drillable cement retainer. In a preferred embodiment, the packer 1155 comprises an EZ Drill Packer
5 available from Halliburton Energy Services in Dallas, TX. In an alternative embodiment, a high gel strength pill may be set below the tie-back in place of the packer 1155. In another alternative embodiment, the packer 1155 may be omitted.

In a preferred embodiment, before or after positioning the apparatus 1100 within the wellbore 1100, a couple of wellbore volumes are circulated in order to
10 ensure that no foreign materials are located within the wellbore 1000 that might clog up the various flow passages and valves of the apparatus 1100 and to ensure that no foreign material interferes with the operation of the expansion mandrel 1105.

As illustrated in Fig. 10c, a hardenable fluidic sealing material 1160 is then pumped from a surface location into the fluid passage 1130. The material 1160 then
15 passes from the fluid passage 1130 into the interior region of the tubular member 1110 below the expandable mandrel 1105. The material 1160 then passes from the interior region of the tubular member 1110 into the fluid passages 1140. The material 1160 then exits the apparatus 1100 and fills the annular region between the exterior of the tubular member 1110 and the interior wall of the tubular liner 1008.
20 Continued pumping of the material 1160 causes the material 1160 to fill up at least a portion of the annular region.

The material 1160 may be pumped into the annular region at pressures and flow rates ranging, for example, from about 0 to 5,000 psi and 0 to 1,500 gallons/min, respectively. In a preferred embodiment, the material 1160 is pumped into the
25 annular region at pressures and flow rates specifically designed for the casing sizes being run, the annular spaces being filled, the pumping equipment available, and the properties of the fluid being pumped. The optimum flow rates and pressures are preferably calculated using conventional empirical methods.

The hardenable fluidic sealing material 1160 may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In a preferred embodiment, the hardenable fluidic sealing material 1160 comprises blended cements specifically designed for well section being tied-back, available from Halliburton Energy Services in Dallas, TX in order to optimally provide proper support for the tubular member 1110 while maintaining optimum flow characteristics so as to minimize operational difficulties during the displacement of cement in the annular region. The optimum blend of the blended cements are preferably determined using conventional empirical methods.

The annular region may be filled with the material 1160 in sufficient quantities to ensure that, upon radial expansion of the tubular member 1110, the annular region will be filled with material 1160.

As illustrated in Fig. 10d, once the annular region has been adequately filled with material 1160, one or more plugs 1165, or other similar devices, preferably are introduced into the fluid passages 1140 thereby fluidically isolating the interior region of the tubular member 1110 from the annular region external to the tubular member 1110. In a preferred embodiment, a non hardenable fluidic material 1161 is then pumped into the interior region of the tubular member 1110 below the mandrel 1105 causing the interior region to pressurize. In a particularly preferred embodiment, the one or more plugs 1165, or other similar devices, are introduced into the fluid passage 1140 with the introduction of the non hardenable fluidic material. In this manner, the amount of hardenable fluidic material within the interior of the tubular member 1110 is minimized.

As illustrated in Fig. 10e, once the interior region becomes sufficiently pressurized, the tubular member 1110 is extruded off of the expandable mandrel 1105. During the extrusion process, the expandable mandrel 1105 is raised out of the expanded portion of the tubular member 1110.

The plugs 1165 are preferably placed into the fluid passages 1140 by introducing the plugs 1165 into the fluid passage 1130 at a surface location in a

conventional manner. The plugs 1165 may comprise any number of conventional commercially available devices from plugging a fluid passage such as, for example, brass balls, plugs, rubber balls, or darts modified in accordance with the teachings of the present disclosure.

5 In a preferred embodiment, the plugs 1165 comprise low density rubber balls. In an alternative embodiment, for a shoe 1105 having a common central inlet passage, the plugs 1165 comprise a single latch down dart.

After placement of the plugs 1165 in the fluid passages 1140, the non hardenable fluidic material 1161 is preferably pumped into the interior region of the
10 tubular member 1110 below the mandrel 1105 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min.

In a preferred embodiment, after placement of the plugs 1165 in the fluid passages 1140, the non hardenable fluidic material 1161 is preferably pumped into the interior region of the tubular member 1110 below the mandrel 1105 at pressures and flow
15 rates ranging from approximately 1200 to 8500 psi and 40 to 1250 gallons/min in order to optimally provide extrusion of typical tubulars.

For typical tubular members 1110, the extrusion of the tubular member 1110 off of the expandable mandrel 1105 will begin when the pressure of the interior region of the tubular member 1110 below the mandrel 1105 reaches, for example,
20 approximately 1200 to 8500 psi. In a preferred embodiment, the extrusion of the tubular member 1110 off of the expandable mandrel 1105 begins when the pressure of the interior region of the tubular member 1110 below the mandrel 1105 reaches approximately 1200 to 8500 psi.

During the extrusion process, the expandable mandrel 1105 may be raised out
25 of the expanded portion of the tubular member 1110 at rates ranging, for example, from about 0 to 5 ft/sec. In a preferred embodiment, during the extrusion process, the expandable mandrel 1105 is raised out of the expanded portion of the tubular member 1110 at rates ranging from about 0 to 2 ft/sec in order to optimally provide

permit adjustment of operational parameters, and optimally ensure that the extrusion process will be completed before the material 1160 cures.

5 In a preferred embodiment, at least a portion 1180 of the tubular member 1110 has an internal diameter less than the outside diameter of the mandrel 1105. In this manner, when the mandrel 1105 expands the section 1180 of the tubular member 1110, at least a portion of the expanded section 1180 effects a seal with at least the wellbore casing 1012. In a particularly preferred embodiment, the seal is effected by compressing the seals 1016 between the expanded section 1180 and the wellbore casing 1012. In a preferred embodiment, the contact pressure of the joint between 10 the expanded section 1180 of the tubular member 1110 and the casing 1012 ranges from about 500 to 10,000 psi in order to optimally provide pressure to activate the sealing members 1145 and provide optimal resistance to ensure that the joint will withstand typical extremes of tensile and compressive loads.

15 In an alternative preferred embodiment, substantially all of the entire length of the tubular member 1110 has an internal diameter less than the outside diameter of the mandrel 1105. In this manner, extrusion of the tubular member 1110 by the mandrel 1105 results in contact between substantially all of the expanded tubular member 1110 and the existing casing 1008. In a preferred embodiment, the contact pressure of the joint between the expanded tubular member 1110 and the casings 20 1008 and 1012 ranges from about 500 to 10,000 psi in order to optimally provide pressure to activate the sealing members 1145 and provide optimal resistance to ensure that the joint will withstand typical extremes of tensile and compressive loads.

25 In a preferred embodiment, the operating pressure and flow rate of the material 1161 is controllably ramped down when the expandable mandrel 1105 reaches the upper end portion of the tubular member 1110. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 1110 off of the expandable mandrel 1105 can be minimized. In a preferred embodiment, the operating pressure of the fluidic material 1161 is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion

process beginning when the mandrel 1105 has completed approximately all but about 5 feet of the extrusion process.

Alternatively, or in combination, a shock absorber is provided in the support member 1150 in order to absorb the shock caused by the sudden release of pressure.

5 Alternatively, or in combination, a mandrel catching structure is provided in the upper end portion of the tubular member 1110 in order to catch or at least decelerate the mandrel 1105.

Referring to Fig. 10f, once the extrusion process is completed, the expandable mandrel 1105 is removed from the wellbore 1000. In a preferred embodiment, either
10 before or after the removal of the expandable mandrel 1105, the integrity of the fluidic seal of the joint between the upper portion of the tubular member 1110 and the upper portion of the tubular liner 1108 is tested using conventional methods. If the fluidic seal of the joint between the upper portion of the tubular member 1110 and the upper portion of the tubular liner 1008 is satisfactory, then the uncured
15 portion of the material 1160 within the expanded tubular member 1110 is then removed in a conventional manner. The material 1160 within the annular region between the tubular member 1110 and the tubular liner 1008 is then allowed to cure.

As illustrated in Fig. 10f, preferably any remaining cured material 1160 within the interior of the expanded tubular member 1110 is then removed in a conventional
20 manner using a conventional drill string. The resulting tie-back liner of casing 1170 includes the expanded tubular member 1110 and an outer annular layer 1175 of cured material 1160.

As illustrated in Fig. 10g, the remaining bottom portion of the apparatus 1100 comprising the shoe 1115 and packer 1155 is then preferably removed by drilling out
25 the shoe 1115 and packer 1155 using conventional drilling methods.

In a particularly preferred embodiment, the apparatus 1100 incorporates the apparatus 900.

Referring now to Figs. 11a-11f, an embodiment of an apparatus and method for hanging a tubular liner off of an existing wellbore casing will now be described.

As illustrated in Fig. 11a, a wellbore 1200 is positioned in a subterranean formation 1205. The wellbore 1200 includes an existing cased section 1210 having a tubular casing 1215 and an annular outer layer of cement 1220.

5 In order to extend the wellbore 1200 into the subterranean formation 1205, a drill string 1225 is used in a well known manner to drill out material from the subterranean formation 1205 to form a new section 1230.

10 As illustrated in Fig. 11b, an apparatus 1300 for forming a wellbore casing in a subterranean formation is then positioned in the new section 1230 of the wellbore 100. The apparatus 1300 preferably includes an expandable mandrel or pig 1305, a tubular member 1310, a shoe 1315, a fluid passage 1320, a fluid passage 1330, a fluid passage 1335, seals 1340, a support member 1345, and a wiper plug 1350.

15 The expandable mandrel 1305 is coupled to and supported by the support member 1345. The expandable mandrel 1305 is preferably adapted to controllably expand in a radial direction. The expandable mandrel 1305 may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the expandable mandrel 1305 comprises a hydraulic expansion tool substantially as disclosed in U.S. Pat. No. 5,348,095, the disclosure of which is incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

20 The tubular member 1310 is coupled to and supported by the expandable mandrel 1305. The tubular member 1310 is preferably expanded in the radial direction and extruded off of the expandable mandrel 1305. The tubular member 1310 may be fabricated from any number of materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing or plastic casing. 25 In a preferred embodiment, the tubular member 1310 is fabricated from OCTG. The inner and outer diameters of the tubular member 1310 may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. In a preferred embodiment, the inner and outer diameters of the tubular member 1310 range from

number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, or plastic tubing/casing. The tubular member 210 is fabricated from OCTG in order to maximize strength after expansion. The inner and outer diameters of the tubular member 210 may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. The inner and outer diameters of the tubular member 210 range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most commonly drilled wellbore sizes. The tubular member 210 preferably comprises a solid member.

10 The end portion 260 of the tubular member 210 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 205 when it completes the extrusion of tubular member 210. The length of the tubular member 210 is limited to minimize the possibility of buckling. For typical tubular member 210 materials, the length of the tubular member 210 is preferably limited to between about 40 to 15 20,000 feet in length.

The shoe 215 is coupled to the expandable mandrel 205 and the tubular member 210. The shoe 215 includes fluid passage 240. The shoe 215 may comprise any number of conventional commercially available shoes such as, for example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. The shoe 215 comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 210 in the wellbore, optimally provide an adequate seal between the interior and exterior diameters of the overlapping joint between the tubular members, and to optimally allow the complete drill out of the shoe and plug after the completion of the cementing and expansion operations.

25 The shoe 215 includes one or more through and side outlet ports in fluidic communication with the fluid passage 240. In this manner, the shoe 215 optimally injects hardenable fluidic sealing material into the region outside the shoe 215 and 30

tubular member 210. The shoe 215 includes the fluid passage 240 having an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage 240 can be optimally sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

5 The lower cup seal 220 is coupled to and supported by the support member 250. The lower cup seal 220 prevents foreign materials from entering the interior region of the tubular member 210 adjacent to the expandable mandrel 205. The lower cup seal 220 may comprise any number of conventional commercially available cup seals such as, for example, TP cups, or Selective Injection Packer
10 (SIP) cups modified in accordance with the teachings of the present disclosure. The lower cup seal 220 comprises a SIP cup seal, available from Halliburton Energy Services in Dallas, TX in order to optimally block foreign material and contain a body of lubricant.

 The upper cup seal 225 is coupled to and supported by the support member
15 250. The upper cup seal 225 prevents foreign materials from entering the interior region of the tubular member 210. The upper cup seal 225 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in accordance with the teachings of the present disclosure. The upper cup seal 225 comprises a SIP cup, available from Halliburton
20 Energy Services in Dallas, TX in order to optimally block the entry of foreign materials and contain a body of lubricant.

 The fluid passage 230 permits fluidic materials to be transported to and from the interior region of the tubular member 210 below the expandable mandrel 205. The fluid passage 230 is coupled to and positioned within the support member 250
25 and the expandable mandrel 205. The fluid passage 230 preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel 205. The fluid passage 230 is preferably positioned along a centerline of the apparatus 200.

 The fluid passage 230 is preferably selected, in the casing running mode of operation, to transport materials such as drilling mud or formation fluids at flow
30 rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to minimize drag on the tubular member being run and to minimize surge

about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most commonly encountered wellbore sizes.

In a preferred embodiment, the tubular member 1310 includes an upper portion 1355, an intermediate portion 1360, and a lower portion 1365. In a preferred embodiment, the wall thickness and outer diameter of the upper portion 1355 of the tubular member 1310 range from about $\frac{3}{8}$ to $1\frac{1}{2}$ inches and $3\frac{1}{2}$ to 16 inches, respectively. In a preferred embodiment, the wall thickness and outer diameter of the intermediate portion 1360 of the tubular member 1310 range from about 0.625 to 0.75 inches and 3 to 19 inches, respectively. In a preferred embodiment, the wall thickness and outer diameter of the lower portion 1365 of the tubular member 1310 range from about $\frac{3}{8}$ to 1.5 inches and 3.5 to 16 inches, respectively.

In a particularly preferred embodiment, the outer diameter of the lower portion 1365 of the tubular member 1310 is significantly less than the outer diameters of the upper and intermediate portions, 1355 and 1360, of the tubular member 1310 in order to optimize the formation of a concentric and overlapping arrangement of wellbore casings. In this manner, as will be described below with reference to Figs. 12 and 13, a wellhead system is optimally provided. In a preferred embodiment, the formation of a wellhead system does not include the use of a hardenable fluidic material.

In a particularly preferred embodiment, the wall thickness of the intermediate section 1360 of the tubular member 1310 is less than or equal to the wall thickness of the upper and lower sections, 1355 and 1365, of the tubular member 1310 in order to optimally facilitate the initiation of the extrusion process and optimally permit the placement of the apparatus in areas of the wellbore having tight clearances.

The tubular member 1310 preferably comprises a solid member. In a preferred embodiment, the upper end portion 1355 of the tubular member 1310 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 1305 when it completes the extrusion of tubular member 1310. In a preferred embodiment, the length of the tubular member 1310 is limited to minimize the possibility of buckling.

For typical tubular member 1310 materials, the length of the tubular member 1310 is preferably limited to between about 40 to 20,000 feet in length.

5 The shoe 1315 is coupled to the tubular member 1310. The shoe 1315 preferably includes fluid passages 1330 and 1335. The shoe 1315 may comprise any number of conventional commercially available shoes such as, for example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or guide shoe with a sealing sleeve for a latch-down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 1315 comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton
10 Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 1310 into the wellbore 1200, optimally fluidically isolate the interior of the tubular member 1310, and optimally permit the complete drill out of the shoe 1315 upon the completion of the extrusion and cementing operations.

15 In a preferred embodiment, the shoe 1315 further includes one or more side outlet ports in fluidic communication with the fluid passage 1330. In this manner, the shoe 1315 preferably injects hardenable fluidic sealing material into the region outside the shoe 1315 and tubular member 1310. In a preferred embodiment, the shoe 1315 includes the fluid passage 1330 having an inlet geometry that can receive
20 a fluidic sealing member. In this manner, the fluid passage 1330 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 1330.

The fluid passage 1320 permits fluidic materials to be transported to and from the interior region of the tubular member 1310 below the expandable mandrel 1305. The fluid passage 1320 is coupled to and positioned within the support member 1345
25 and the expandable mandrel 1305. The fluid passage 1320 preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel 1305. The fluid passage 1320 is preferably positioned along a centerline of the apparatus 1300. The fluid passage 1320 is preferably selected to transport materials such as cement, drilling mud, or epoxies at flow rates and pressures ranging from about 0 to 3,000

gallons/minute and 0 to 9,000 psi in order to optimally provide sufficient operating pressures to circulate fluids at operationally efficient rates.

5 The fluid passage 1330 permits fluidic materials to be transported to and from the region exterior to the tubular member 1310 and shoe 1315. The fluid passage 1330 is coupled to and positioned within the shoe 1315 in fluidic communication with the interior region 1370 of the tubular member 1310 below the expandable mandrel 1305. The fluid passage 1330 preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in fluid passage 1330 to thereby block further passage of fluidic materials. In this manner, the interior region 1370 of the tubular member 1310 below the expandable mandrel 1305 can be fluidically isolated from the region exterior to the tubular member 1310. This permits the interior region 1370 of the tubular member 1310 below the expandable mandrel 1305 to be pressurized. The fluid passage 1330 is preferably positioned substantially along the centerline of the apparatus 1300.

15 The fluid passage 1330 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member 1310 and the new section 1230 of the wellbore 1200 with fluidic materials. In a preferred embodiment, the fluid passage 1330 includes an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage 1330 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 1330.

25 The fluid passage 1335 permits fluidic materials to be transported to and from the region exterior to the tubular member 1310 and shoe 1315. The fluid passage 1335 is coupled to and positioned within the shoe 1315 in fluidic communication with the fluid passage 1330. The fluid passage 1335 is preferably positioned substantially along the centerline of the apparatus 1300. The fluid passage 1335 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order

to optimally fill the annular region between the tubular member 1310 and the new section 1230 of the wellbore 1200 with fluidic materials.

5 The seals 1340 are coupled to and supported by the upper end portion 1355 of the tubular member 1310. The seals 1340 are further positioned on an outer surface of the upper end portion 1355 of the tubular member 1310. The seals 1340 permit the overlapping joint between the lower end portion of the casing 1215 and the upper portion 1355 of the tubular member 1310 to be fluidically sealed. The seals 1340 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the seals 1340 10 comprise seals molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a hydraulic seal in the annulus of the overlapping joint while also creating optimal load bearing capability to withstand typical tensile and compressive loads.

15 In a preferred embodiment, the seals 1340 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 1310 from the existing casing 1215. In a preferred embodiment, the frictional force provided by the seals 1340 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 1310.

20 The support member 1345 is coupled to the expandable mandrel 1305, tubular member 1310, shoe 1315, and seals 1340. The support member 1345 preferably comprises an annular member having sufficient strength to carry the apparatus 1300 into the new section 1230 of the wellbore 1200. In a preferred embodiment, the support member 1345 further includes one or more conventional centralizers (not 25 illustrated) to help stabilize the tubular member 1310.

In a preferred embodiment, the support member 1345 is thoroughly cleaned prior to assembly to the remaining portions of the apparatus 1300. In this manner, the introduction of foreign material into the apparatus 1300 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and

valves of the apparatus 1300 and to ensure that no foreign material interferes with the expansion process.

5 The wiper plug 1350 is coupled to the mandrel 1305 within the interior region 1370 of the tubular member 1310. The wiper plug 1350 includes a fluid passage 1375 that is coupled to the fluid passage 1320. The wiper plug 1350 may comprise one or more conventional commercially available wiper plugs such as, for example, Multiple Stage Cementer latch-down plugs, Omega latch-down plugs or three-wiper latch-down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the wiper plug 1350 comprises a Multiple Stage Cementer
10 latch-down plug available from Halliburton Energy Services in Dallas, TX modified in a conventional manner for releasable attachment to the expansion mandrel 1305.

In a preferred embodiment, before or after positioning the apparatus 1300 within the new section 1230 of the wellbore 1200, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore
15 1200 that might clog up the various flow passages and valves of the apparatus 1300 and to ensure that no foreign material interferes with the extrusion process.

As illustrated in Fig. 11c, a hardenable fluidic sealing material 1380 is then pumped from a surface location into the fluid passage 1320. The material 1380 then passes from the fluid passage 1320, through the fluid passage 1375, and into the
20 interior region 1370 of the tubular member 1310 below the expandable mandrel 1305. The material 1380 then passes from the interior region 1370 into the fluid passage 1330. The material 1380 then exits the apparatus 1300 via the fluid passage 1335 and fills the annular region 1390 between the exterior of the tubular member 1310 and the interior wall of the new section 1230 of the wellbore 1200. Continued pumping
25 of the material 1380 causes the material 1380 to fill up at least a portion of the annular region 1390.

The material 1380 may be pumped into the annular region 1390 at pressures and flow rates ranging, for example, from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively. In a preferred embodiment, the material 1380 is pumped

into the annular region 1390 at pressures and flow rates ranging from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively, in order to optimally fill the annular region between the tubular member 1310 and the new section 1230 of the wellbore 1200 with the hardenable fluidic sealing material 1380.

5 The hardenable fluidic sealing material 1380 may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In a preferred embodiment, the hardenable fluidic sealing material 1380 comprises blended cements designed specifically for the well section being drilled and available from Halliburton Energy Services in order to
10 optimally provide support for the tubular member 1310 during displacement of the material 1380 in the annular region 1390. The optimum blend of the cement is preferably determined using conventional empirical methods.

The annular region 1390 preferably is filled with the material 1380 in sufficient quantities to ensure that, upon radial expansion of the tubular member
15 1310, the annular region 1390 of the new section 1230 of the wellbore 1200 will be filled with material 1380.

As illustrated in Fig. 11d, once the annular region 1390 has been adequately filled with material 1380, a wiper dart 1395, or other similar device, is introduced into the fluid passage 1320. The wiper dart 1395 is preferably pumped through the fluid
20 passage 1320 by a non hardenable fluidic material 1381. The wiper dart 1395 then preferably engages the wiper plug 1350.

As illustrated in Fig. 11e, in a preferred embodiment, engagement of the wiper dart 1395 with the wiper plug 1350 causes the wiper plug 1350 to decouple from the mandrel 1305. The wiper dart 1395 and wiper plug 1350 then preferably will lodge
25 in the fluid passage 1330, thereby blocking fluid flow through the fluid passage 1330, and fluidically isolating the interior region 1370 of the tubular member 1310 from the annular region 1390. In a preferred embodiment, the non hardenable fluidic material 1381 is then pumped into the interior region 1370 causing the interior region 1370 to pressurize. Once the interior region 1370 becomes sufficiently pressurized, the